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Decision 20-02-045 February 27, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of SOUTHERN CALIFORNIA GAS COMPANY (U904G) and SAN DIEGO GAS & ELECTRIC COMPANY (U902G) for authority to revise their natural gas rates and implement storage proposals effective January 1, 2020 in this Triennial Cost Allocation Proceeding.	Application 18-07-024

DECISION ADDRESSING SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY TRIENNIAL COST ALLOCATION PROCEEDING APPLICATION

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DECISION ADDRESSING SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY TRIENNIAL COST ALLOCATION PROCEEDING APPLICATION

Summary

This decision adopts demand forecasts for core and noncore customers in the San Diego Gas & Electric Company and Southern California Gas Company (Applicants) territories, as proposed by Applicants. These forecasts feed into the embedded cost method for transmission and storage functions and the Long Run Marginal Cost method for customer costs, which we authorize Applicants to use—with modifications—to allocate the costs across customer classes. We determine that neither the Rental Method nor the New Customer Only Method for determining marginal costs are optimal approaches. However, for the 2020-2022 Triennial Cost Allocation Proceeding cycle, we authorize Applicants to use the Rental Method, as its results provide marginal costs with less dramatic increases across all customer classes. We adopt a modified version of a proposal developed by the Commission's Energy Division to allocate storage capacity based on the shifting inventory capacity of the Aliso Canyon Storage Facility. The decision also addresses several requests related to regulatory accounts and other administrative processes, extends the Second Daily Balancing Settlement through 2022, and adopts Applicants' proposal to implement Senate Bill 711. Application 18-07-024 is closed.

1. Background

The purpose of a triennial cost allocation proceeding (TCAP) is to consider proposals to allocate costs of providing natural gas service among customer classes, broadly categorized as core customers and noncore customers.[1] Core

[1] Application at 1.

customers can be described as predominantly residential customers but also small commercial and industrial customers, including core aggregation transportation customers. Noncore customers include medium and large commercial and industrial customers, electric generators, and wholesale customers. In addition to cost allocation, this proceeding also addresses gas storage-related proposals, which effect the reliability of the natural gas system and the allocation of the storage costs.

On July 31, 2018, Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) (jointly, Applicants) filed this application requesting authority to revise their natural gas rates and to implement storage proposals, effective January 1, 2020. The application covers the three-year period of January 1, 2020 through December 31, 2022.[2] The following parties filed responses to the application: Environmental Defense Fund, Small Business Utility Advocates (SBUA), Shell Energy North American (Shell Energy), and Southern California Edison Company (SCE).
Public Advocates Office of the California Public Utilities Commission (Public Advocates Office), Southern California Generation Coalition (SCGC), and The Utility Reform Network (TURN) filed protests to the application. The responses and protests were timely filed.

Pursuant to Commission Rules of Practice and Procedure, Rule 3.2(e), on September 20, 2018, Applicants filed proof of compliance with the following notice requirements: i) mailing the notice of application to all applicable state, city, and county agencies, in accordance with Rule 3.2(b); ii) posting the notice in all the applicable division and payment offices for viewing; iii) newspaper

[2] Prior to 2011, the natural gas cost allocation proceedings were biennial.

publication of the notice, in accordance with Rule 3.2(c); and iv) mailing the notice to customers, in accordance with Rule 3.2(d).

A prehearing conference was held on October 16, 2018 to discuss the issues of law and fact and determine the need for hearing and schedule for resolving the matter. After consideration of the application, protests, responses, and discussion at the prehearing conference, an *Assigned Commissioner's Scoping Memo and Joint Assigned Commissioner's and Administrative Law Judge's Ruling* (Scoping Memo) was issued on October 31, 2018 identifying the issues and schedule of the proceeding.

The Scoping Memo also addressed Senate Bill (SB) 711 (Stats. 2017, Ch. 467), which requires the Commission to make efforts to minimize bill volatility for residential customers, by modifying the length of baseline seasons or defining additional baseline seasons. Additionally, for gas corporations that, for some portion of residential customers, employ every-other-month meter reading and estimate bills for months when the customer's meter is not read, SB 711 requires the Commission to direct the gas corporation to include in its tariffs the methodology it employs to estimate bills for those months during which the meter is not read. The Scoping Memo directed parties to respond to two questions regarding SB 711: 1) why this proceeding is or is not the appropriate proceeding to implement SB 711 and 2) if this proceeding is appropriate, what is a reasonable timeline and procedural venue to require Applicants to recommend a proposal to comply with SB 711.

Parties filed responses to the SB 711 questions on November 12, 2018 and reply comments on November 19, 2018. As a result of responses to those questions, the Administrative Law Judge issued a ruling finding that SB 711 should be addressed in this proceeding and directing Applicants to serve supplemental testimony and supporting workpapers proposing a plan to implement SB 711. On February 22, 2019, Applicants submitted supplemental testimony, as directed.

On March 21, 2019, the Administrative Law Judge facilitated a workshop at which time parties discussed Applicants' gas system and gas storage system and related Applicant and party proposals.

The Administrative Law Judge presided over an evidentiary hearing from June 10, 2019 through June 14, 2019. Parties filed opening briefs on July 26, 2019 and reply briefs on August 16, 2019.

The Administrative Law Judge stated during the evidentiary hearing that the record would be submitted with the filing of reply briefs. However, on October 3, 2019, the Administrative Law Judge issued a ruling setting aside submission to introduce and take comment on the *Energy Division Staff Proposal on Storage Capacity Allocation* (Staff Proposal). Parties filed comments on the Staff Proposal on October 24, 2019 and reply comments on October 31, 2019.

The record for this proceeding was resubmitted on October 31, 2019. Application 18-07-024 is closed.

2. Issues Before the Commission

The Scoping Memo identified the following 13 issues for this proceeding. We describe these issues in detail in Sections 3 and 6 below:

1. Whether to authorize the demand forecasts used for setting transportation rates as proposed in this proceeding, to become effective January 1, 2020;
2. Whether to approve the storage allocation proposals in this proceeding, including elimination of the Unbundled Storage Program and use of storage assets to support core reliability function, enhanced balancing function, and new reliability function;

3. Whether to authorize SoCalGas to procure gas to fulfill the enhanced balancing function and the new reliability function;
4. Whether to authorize the allocation of costs by customer classes as proposed in this proceeding to become effective January 1, 2020;
5. Whether to authorize proposed transportation rates to become effective January 1, 2020;
6. Whether to authorize proposed residential customer charges;
7. Whether to authorize proposed modifications to Applicants' existing regulatory accounts;
8. Whether to authorize two new regulatory accounts and associated cost recovery mechanisms for SoCalGas: (i) Storage Inventory for Balancing Function Memorandum Account (SIBFMA) and (ii) Reliability Function Cost Memorandum Account (RFCMA);
9. Whether to authorize the continued 100 percent balancing account treatment for Applicants' noncore transportation revenue requirement as currently contained in the Noncore Fixed Cost Account;
10. Whether to authorize Applicants' regulatory account treatments as being effective on an ongoing basis unless or until the Commission approves future modifications;
11. Whether to provide explicit authority for Applicants to continue their annual regulatory account balance updates through their existing advice letter process, the filings of which occur in October;
12. Whether the Commission should extend, make permanent, revise, or terminate the provisions of the Second Settlement approved in Decision (D.) 16-12-015 and subsequently extended to November 30, 2018 by D.17-11-021; and
13. Whether the Commission should consider the implementation of SB 711 in this proceeding and, if so, how should Applicants implement SB 711?

3. Overview of the Application

The following is a synopsis of Applicants' proposals for the Commission to consider in this proceeding. The proposals listed here are discussed in detail in Section 6. Applicants propose to:

- Dedicate storage facilities to core customers, increased system balancing, and the proposed reliability functions, and eliminate the Unbundled Storage Program;
- Reduce total storage inventory capacity from 138.1 billion cubic feet (Bcf) to 119.5 Bcf due to a change in the maximum allowable inventory at the Aliso Canyon Storage Facility (Aliso)[3] established by the Division of Oil, Gas and Geothermal Resources rules,[4] and based on unrestricted injection and withdrawal at Aliso;
- Create regulatory accounts to track and recover the costs of the balancing[5] and reliability[6] functions;
- Procure 8 Bcf of gas for balancing and 21 Bcf for reliability functions;
- Modify SoCalGas's Noncore Storage Balancing Account to eliminate the provisions related to the Unbundled Storage Program and sharing mechanism;
- Obtain storage capacities for wholesale core customers[7] in the Unbundled Storage Program from core storage assets, and record revenues in SoCalGas's Core Fixed Asset Account;

[3] SoCalGas owns and operates four underground storage facilities: Aliso, Honor Rancho, La Goleta, and Playa Del Rey.

[4] On July 19, 2017, the Division of Oil, Gas, and Geothermal Resources determined that Aliso could be safely operated at pressures between 1,080 and 2,926 pounds per square inch. This translates to an inventory ranging from 0 to 68.6 Bcf.

[5] Storage Inventory for SIBFMA.

[6] Storage Inventory for RFCMA.

[7] SoCalGas's wholesale core customers are Southwest Gas and City of Long Beach.

- Establish SoCalGas and SDG&E annual regulatory account balance update advice letter process;
- Eliminate SDG&E's Liquefied Natural Gas Service Tracking Account[8], and direct as to whether existing tariff provisions for regulatory accounts in the Preliminary Statement are to remain in effect;
- Maintain storage costs for the Aliso Turbine Replacement placed in service on May 17, 2018, at the level consistent with prior TCAP decisions D.14-06-007 and D.16-06-039;
- Maintain transmission costs at the level consistent with prior TCAP decisions D.14-06-007 and D.16-10-004;
- Allocate 82.5 Bcf of underground storage inventory, 445 million per cubic feet per day (MMcfd) of summer injection, 155 MMcfd of winter injection, 2,000 MMcfd of winter withdrawal capacity, and 400 MMcfd of summer withdrawal, to core customers, at a total cost of $88.2 million;
- Allocate 16 Bcf of storage inventory, 345 MMcfd of injection, 400 MMcfd of winter withdrawal, and 840 MMcfd of summer withdrawal capacities to the balancing function, at a total cost of $65.2 million;
- Allocate remaining storage inventory of 21 Bcf to the reliability function at $8.3 million in cost;
- Continue to use the Long Run Marginal Cost[9] (LRMC) method to allocate the authorized revenue requirement, customer-related, medium-pressure distribution-related, and high-pressure distribution-related costs, to customer

[8] SDG&E's Liquefied Natural Gas Service Tracking Account, established in its 1994 Biennial Cost Allocation Proceeding, tracks the difference between actual cost of providing liquified natural gas services to the Roadrunner Mobilehome Park and the revenues collected therefrom. Because rate structure does not allow recovery of the balance, SDG&E requests elimination of the account.

[9] LRMC is the incremental cost to serve one additional unit in the long run; such a unit cost is called marginal unit cost.

classes, as proposed in the last TCAP (Application (A.) 15-07-014; D.16-10-004). Allocate transmission and storage functions using embedded cost method as proposed in the last TCAP;

- Create a new, optional cost-based core transportation rate for service to small electric generators;[10] and
- Use methods consistent with 2017 TCAP Phase 2 as required by D.16-10-004 to develop and allocate non-marginal costs, with some exceptions.[11]

4. Background Information on the Aliso Canyon Storage Facility

The Scoping Memo of this proceeding listed one of the scoped issues as whether to approve the storage proposals in this proceeding. Hence, it is relevant to provide related information regarding Aliso.

Applicants report that its largest storage facility, Aliso, experienced a gas leak on October 23, 2015. The gas leak was permanently sealed on February 18, 2016 and, on July 19, 2017, the Division of Oil, Gas and Geothermal Resources established a maximum allowable inventory of 68.6 Bcf for Aliso.

Public Utilities Code Section 715 requires the Commission to determine the range of working gas necessary to ensure safety and reliability for the region and just and reasonable rates in California. Subsequently, the Commission

[10] Small electric generators are those eligible for core services pursuant to Electric Rule 23 (Core service priority 1 includes all electric generators, refinery and enhanced oil recovery usage less than 20,800 therms per active month electing core service).

[11] Exceptions include: a) increase residential customer charge from $5 to $10 per customer per month for SoCalGas; b) replace residential minimum bill from $3 per customer per month to $10 per customer per month for SDG&E; c) provide new method to allocate self-generation incentive program costs; and d) propose methods to allocate new Storage Inventory for SIBFMA and RFCMA costs across customer classes.

established an Aliso allowable inventory of 34 Bcf.[12] In addition, Aliso is currently under a Commission-imposed Withdrawal Protocol, which defines the conditions under which SoCalGas may withdraw natural gas from Aliso.

Pursuant to the July 23, 2019 Withdrawal Protocol, Aliso may be used for withdrawals only if any of the following conditions are met:[13]

1. Preliminary[14] low Operational Flow Order (OFO) calculations for any cycle result in a Stage 2 low OFO or higher for the applicable gas day;
2. Aliso is above 70 percent of its maximum allowable inventory between February 1 and March 31; in such case, SoCalGas may withdraw from Aliso until inventory declines to 70 percent of its maximum allowable inventory;[15]
3. The Honor Rancho and/or La Goleta fields decline to 110 percent of their month-end minimum inventory requirements (shown in the table below) during the winter season;[16] and/or

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[12] Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity, and Well Availability for Reliability Supplemental Report, July 2, 2018. This is also known as the 715 Report.

[13] The complete Withdrawal Protocol, dated July 23, 2019 can be found at: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf

[14] Preliminary low OFO calculations for a Gas Day shall be made: 1) prior to Cycle 1 using previous day's receipts, previous day's prices, and forecasted sendouts; 2) prior to Cycle 2; and 3) prior to Cycle 3.

[15] This measure is designed to ensure that there is enough systemwide injection capacity by April 1 (the start of the injection season) to fill the non-Aliso fields to a sufficient inventory level to meet summer demand.

[16] This measure is designed to ensure that adequate inventory levels remain at the non-Aliso fields before the end of each winter month. SoCalGas' Aliso Canyon Risk Assessment Technical Report 2018-19 Supplement identified month-end minimum inventory requirements needed to preserve withdrawal rates for core reliability. The report can be found here:

Footnote continued on next page.

4. There is an imminent and identifiable risk of gas curtailments created by an emergency condition that would impact public health and safety or result in curtailments of electric load that could be mitigated by withdrawals from Aliso.

Month-End Minimum Inventory (Bcf)					
	November	December	January	February	March
Aliso Canyon	5.7	5.1	4.4	3.8	2.1
Honor Rancho	13.9	13.2	12.6	7.5	5.0
La Goleta	8.0	7.9	7.7	7.6	7.5
Playa del Rey	1.9	1.9	1.5	1.1	0.7
Total	29.5	28.1	26.2	20.0	15.3

5. Summary of the October 3, 2019 Staff Proposal on Storage Allocation

According to the Staff Proposal, Applicants' storage allocation proposal conflicts with the current operational restrictions at Aliso. Applicants request storage allocations based on the highest possible maximum inventory allowable at Aliso. While SCGC proposed an allocation breakdown for Aliso at 34 Bcf, no party proposed a mechanism to adjust for the actual storage allocations for Aliso. Staff explains that because there is regulatory uncertainty regarding the amount of capacity that will be allowed at Aliso in the short and long term, Aliso's inventory capacity could range anywhere from 0 Bcf to 68.6 Bcf. The Staff Proposal recommends that, because of this regulatory uncertainty, the Commission should adopt a mechanism whereby storage capacity can be allocated based on the current capacity using the embedded cost method to allocate storage costs, which applies recorded costs.

The Staff Proposal recommends that the functionalized storage costs allocated to inventory, injection, and withdrawal be subsequently apportioned to

http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2018/2018%2011%2002%20SoCalGas%20(R.%20Schwecke)%20letter%20to%20CEC%20enclosing%20WINTER%202018-19%20TECHNICAL%20ASSESSMENT.PDF core and balancing functions, based on the Staff Proposal's storage capabilities or modified as necessary if Aliso's maximum allowable inventory changes.

As indicated below, the Staff Proposal accommodates the shifting inventory by providing three scenarios of Aliso inventory: Aliso at a capacity of 34 Bcf, both with and without the Withdrawal Protocol (Current Capacity Scenario), Aliso at a capacity of 0 to 33 Bcf (Decreased Capacity Scenario), and Aliso at a capacity between 34.1 and 68.6 Bcf, with and without the Withdrawal Protocol (Increased Capacity Scenario).

In the Current Capacity Scenario, the Staff Proposal recommends allocating storage as shown in Tables 1 and 2 below. As noted in the Staff Proposal, the Withdrawal Protocol dictates when SoCalGas can initiate withdrawals from the field. The Staff Proposal maintains it is essential to consider the actual total withdrawal capacity for the winter and summer seasons when allocating storage amounts. Therefore, the Staff Proposal allocates two different withdrawal amounts to core customers and the balancing function to account for the impact of the Withdrawal Protocol. Table 1 represents the allocations at an Aliso capacity of 34 Bcf, if the Withdrawal Protocol is triggered, allowing access to Aliso inventory. Table 2 represents the allocations at a capacity of 34 Bcf, without the use of Aliso.

The Staff Proposal provides several caveats in the Current Capacity Scenario. With respect to core inventory requirements, the Staff Proposal contends that a new reliability function is not supported when Aliso's inventory capacity is at 34 Bcf. The Staff Proposal maintains that it is crucial to both core and gas system reliability that core customers be able to inject gas into storage. Hence, the Staff Proposal recommends that if total injection capacity falls below 445 MMcfd, core customers should be guaranteed at least 100 MMcfd of injection capacity or 50 percent of total injection capacity, whichever is less. With respect to wholesale core customers, for the Current Capacity Scenario, the Staff Proposal recommends that wholesale customers be allocated a portion of all core storage assets.[17] While Applicants request to allocate an additional 8 Bcf of storage inventory to the load balncing function (for a total of 16 Bcf), the Staff Proposal limits the amount in the Current Capacity Scenario to the current 8 Bcf. Furthermore, with Aliso at a capacity of 34 Bcf, the Staff Proposal maintains the Unbundled Storage Program is not feasible and, therefore, allocates zero capacity to either the injection or withdrawal aspects of the Unbundled Storage Program.

[17] Southwest Gas will be allocated storage capacities equal to 2 percent of the storage capacities allocated to core customers and the City of Long Beach will be allocated storage capacities equal to 1 percent of the storage capacities allocated to core customers.

Table 1 **Current Capacity Scenario** **Aliso Inventory at 34 Bcf / Aliso Withdrawal Capacity Available**	
Total Storage Inventory	84.9 Bcf
Winter Withdrawal Capacity	2,660 MMcfd[18]
Summer Withdrawal Capacity	1,390 MMcfd-2,340 MMcfd[19]
Winter Injection Capacity	500 MMcfd[20]
Summer Injection Capacity	790 MMcfd[21]
Core Inventory	76.9 Bcf
Injection (Summer)	445 MMcfd[22]
Injection (Winter)	155 MMcfd[23]
Withdrawal (Summer)	400 MMcfd
Withdrawal (Winter)	2,000 MMcfd
Load Balancing Inventory	8 Bcf
Injection (Summer)	345 MMcfd
Injection (Winter)	345 MMcfd
Withdrawal (Summer)	840 MMcfd
Withdrawal (Winter)	400 MMcfd
Unbundled Storage Program	-
Injection (Summer)	-
Injection (Winter)	-
Withdrawal (Summer)	-
Withdrawal (Winter)	-

[18] Derived from Table 3 of SoCalGas' Winter 2018-19 Technical Assessment: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2018/2018%2011%2002%20SoCalGas%20(R.%20Schwecke)%20letter%20to%20CEC%20enclosing%20WINTER%202018-19%20TECHNICAL%20ASSESSMENT.PDF

[19] Derived from SoCalGas' 2019 Summer Technical Assessment: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/SoCalGas%20Summer%202019%20Technical%20Assessment%20040219.pdf

[20] APP-01 at 5.

[21] *Ibid*.

[22] Injection capacity decreases as storage fields are filled. Core customers shall be guaranteed at least 100 MMcfd or 50 percent of total system injection capacity, whichever is lesser.

[23] Footnote 15.

Table 2 Current Capacity Scenario Aliso Inventory at 34 Bcf / Aliso Withdrawal Capacity Unavailable	
Total Storage Inventory	84.9 Bcf
Winter Withdrawal Capacity	1,343 MMcfd[24]
Summer Withdrawal Capacity	910 MMcfd[25]
Winter Injection Capacity	500 MMcfd[26]
Summer Injection Capacity	790 MMcfd[27]
Core Inventory	76.9 Bcf
Injection (Summer)	445 MMcfd[28]
Injection (Winter)	155 MMcfd[29]
Withdrawal (Summer)	400 MMcfd
Withdrawal (Winter)	1,093 MMcfd
Load Balancing Inventory	8 Bcf
Injection (Summer)	345 MMcfd
Injection (Winter)	345 MMcfd
Withdrawal (Summer)	350 MMcfd[30]
Withdrawal (Winter)	250 MMcfd[31]
Unbundled Storage Program	-
Injection (Summer)	-
Injection (Winter)	-
Withdrawal (Summer)	-
Withdrawal (Winter)	-

Noting that the current TCAP will be in effect until 2022, the Staff Proposal cautions that the Commission may decide that the inventory capacity for Aliso should be further reduced. Hence, the Staff Proposal provides a second scenario

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[24] Derived from Table 3 of SoCalGas' Winter 2018-19 Technical Assessment

[25] Average 2018 Summer Withdrawal Capacity from SoCalGas' Envoy: https://scgenvoy.sempra.com/

[26] APP-01 at 5.

[27] *Ibid.*

[28] Footnote 12.

[29] *Ibid.*

[30] *See* SoCalGas-01 at Table 14.

[31] *Ibid.*

where Aliso's maximum inventory capacity ranges from 0 Bcf to 33.9 Bcf, the Decreased Capacity Scenario. As indicated in Table 3 below, the Staff Proposal recommends that, in this scenario, 80 percent of the available winter withdrawal capacity be allocated to core customers and for the summer months, 40 percent of withdrawal capacity be allocated to core customers. Furthermore, because there will be less injection capacity on the system with reduced inventory, the Commission should ensure that core customers are able to inject gas into storage to meet winter reliability needs. As such, the Staff Proposal recommends 345 MMcfd of injection capacity be allocated to the balancing function and the remainder of injection capacity on the system be allocated to core customers until capacity falls below 445 MMcd. The Staff Proposal offers that if total injection capacity falls below 445 MMcfd, core customers should be guaranteed at least 100 MMcfd of injection capacity or 50 percent of total injection capacity, whichever is less.

In the Decreased Capacity Scenario, wholesale customers would receive the same allocation as Aliso at 34 Bcf. As was the case with Aliso at 34 Bcf, the Staff Proposal considers the Unbundled Storage Program to continue to be infeasible in this scenario. Thus, the Staff Proposal submits that 8 Bcf to the balancing function is essential in assisting transportation customers to manage uncertainty related to gas demand and supply. Consistent with current allocations, 20 percent of the available winter withdrawal capacity will serve the balancing function and, in the summer months, 60 percent of the withdrawal capacity will be allocated to the balancing function.

Table 3 **Decreased Capacity Scenario** **Aliso Inventory at 0-33.9 Bcf**[32]	
Total Storage Inventory	50.9-84.8 Bcf
Winter Withdrawal Capacity	1,343MMcfd-2,660 MMcfd
Summer Withdrawal Capacity	910 MMcfd-2,340 MMcfd
Winter Injection Capacity	500 MMcfd[33]
Summer Injection Capacity	790 MMcfd[34]
Core Inventory	42.9-76.8 Bcf
Injection (Summer)	Total-345 MMcfd If total less than 445 MMcfd, Core receives 100 MMcfd or 50% of total, whichever is less
Injection (Winter)	See above
Withdrawal (Summer)	40%
Withdrawal (Winter)	80%
Load Balancing Inventory	8 Bcf
Injection (Summer)	345 MMcfd
Injection (Winter)	345 MMcfd
Withdrawal (Summer)	60%
Withdrawal (Winter)	20%
Unbundled Storage Program	-
Injection (Summer)	-
Injection (Winter)	-
Withdrawal (Summer)	-
Withdrawal (Winter)	-

In the third scenario, the Staff Proposal contemplates that Aliso's inventory capacity is increased above the current 34 Bcf to as high as the maximum allowable inventory of 68.6 Bcf, the Increased Capacity Scenario. In this scenario, core customers would receive an incremental increase until their capacity reaches

[32] Withdrawal capacity is allocated on a percentage basis in this scenario; therefore, this table accounts for both a scenario where Aliso's withdrawal capacity is available and a scenario where Aliso's withdrawal capacity is unavailable.

[33] If Aliso's maximum inventory capacity is 0 Bcf, then core customers shall be guaranteed 50% of the total injection capacity on the system.

[34] *See* Footnote 27.

82.5 Bcf. For example, if Aliso's inventory capacity is increased to 40 Bcf, the total storage inventory would be 90.9 Bcf and core's allocation would increase from 76.9 Bcf to 82.5 Bcf.

As shown in Table 4 below, Staff proposes that the injection capacities allocated to core customers could be supported at any inventory level between total storage range of 85.9 Bcf and 119.5 Bcf. In the Increased Capacity Scenario, core customers are allocated 155 MMcfd of winter injection capacity and 445 MMcfd of summer injection capacity. Here, if total injection capacity falls below 445 MMcfd, staff proposes core customers be guaranteed 100 MMcfd of injection capacity or 50 percent of total injection capacity, whichever is less. If Aliso's withdrawal capacity is available, staff proposes that core customers be allocated 2,000 MMcfd of winter withdrawal capacity and 400 MMcfd of summer withdrawal capacity. But if withdrawal capacity is not available, staff proposes core customers be allocated 1,093 MMcfd of winter withdrawal capacity and 400 MMcfd of summer withdrawal capacity.

In the Increased Capacity Scenario, wholesale core customers will receive the same allocation as in the 34 Bcf scenario. With respect to the balancing function, once core's allocation reaches 82.5 Bcf, staff proposes any additional inventory increase be allocated to the balancing function until it reaches 10 Bcf. Furthermore, if Aliso's withdrawal capacity is available, staff recommends the balancing function receive an allocation of 400 MMcfd of winter withdrawal capacity and 840 MMcfd of Summer withdrawal capacity. If Aliso withdrawal capacity is not available, staff proposes the balancing function would receive 250 MMcfd of winter withdrawal capacity and 350 MMcfd of summer withdrawal capacity. Lastly, staff recommends that the balancing function receive 345 MMcfd of injection capacity in summer and winter, except where total injection capacity falls below 445 MMcfd.

Table 4 Increased Capacity Scenario Aliso Capacity at 34.1 Bcf-68.6 Bcf / Aliso Withdrawal Capacity Available	
Total Storage Capacity at 85 Bcf-119.5 Bcf	
Winter Withdrawal Capacity	2,660 MMcfd+
Summer Withdrawal Capacity	2,340 MMcfd+
Winter Injection Capacity	500 MMcfd
Summer Injection Capacity	790 MMcfd
Core Inventory	77 Bcf-82.5 Bcf
Injection (Summer)	445 MMcfd
Injection (Winter)	155 MMcfd
Withdrawal (Summer)	400 MMcfd
Withdrawal (Winter)	2,000 MMcfd
Load Balancing Inventory	8 Bcf-10 Bcf
Injection (Summer)	345 MMcfd
Injection (Winter)	345 MMcfd
Withdrawal (Summer)	840 MMcfd
Withdrawal (Winter)	400 MMcfd
Unbundled Storage Program	0- 27 Bcf[35]
Injection (Summer)	Interruptible
Injection (Winter)	Interruptible
Withdrawal (Summer)	Interruptible
Withdrawal (Winter)	Interruptible

[35] Staff recommends incrementally allocating 27 Bcf to the Unbundled Storage Program, if the total storage inventory capacity is 92.5 Bcf or above.

Table 5 Increased Capacity Scenario Aliso Capacity at 34.1 Bcf - 68.6 Bcf Aliso Withdrawal Capacity Unavailable	
Total Storage Capacity at 85 Bcf- 119.5 Bcf	
Winter Withdrawal Capacity	1,343 MMcfd
Summer Withdrawal Capacity	910 MMcfd
Winter Injection Capacity	500 MMcfd
Summer Injection Capacity	790 MMcfd
Core Inventory	77 Bcf-82.5 Bcf
Injection (Summer)	445 MMcfd
Injection (Winter)	155 MMcfd
Withdrawal (Summer)	400 MMcfd
Withdrawal (Winter)	1,093 MMcfd
Load Balancing Inventory	8 Bcf-10 Bcf
Injection (Summer)	345 MMcfd
Injection (Winter)	345 MMcfd
Withdrawal (Summer)	350 MMcfd
Withdrawal (Winter)	250 MMcfd
Unbundled Storage Program	0-27 Bcf[36]
Injection (Summer)	Interruptible
Injection (Winter)	Interruptible
Withdrawal (Summer)	Interruptible
Withdrawal (Winter)	Interruptible

In the Increased Capacity Scenario, the Staff Proposal recommends that if the total storage inventory capacity reaches 92.5 Bcf or higher, any additional inventory capacity should be allocated to the Unbundled Storage Program for a maximum total storage capacity of 27 Bcf. Staff also proposes that SoCalGas be financially at risk for storage inventory allocated to the Unbundled Storage Program and any profits from the unbundled storage should be subject to the sharing mechanism. Further, Staff recommends the Commission not adopt the reliability function proposed by Applicants if this scenario is in play.

[36] *See* Footnote 30.

The final element of the Staff Proposal is storage cost allocation. Staff recommends that the functionalized storage costs be allocated to inventory, injection and withdrawal but apportioned to the core and load balancing storage functions based on the proposed storage capacities in Table 1 above or modified as necessary if Aliso's inventory changes.

6. Adoption of Cost Allocation and Storage Proposals

Below we address the 13 issues designated in the Scoping Memo for this proceeding. We begin with a discussion of the demand forecast (Issue 1), followed by the allocation of costs (Issue 4) and storage allocation (Issues 2 and 3). We then address rates, including transportation rates (Issue 5) and residential customer charges (Issue 6). The final sections address regulatory accounts (Issues 7-11), the Second Settlement (Issue 12), and the implementation of SB 711(Issue 13). All issues in the scope of this proceeding having been resolved, the Commission should close A.18-07-024.

6.1. Applicants' Demand Forecast is Reasonable

We adopt Applicants' demand forecasts for core and noncore customers, which received support by Public Advocates Office and, with one small exception, TURN. As described below, SCGC's proposal decreasing peak day and cold year peak month demand forecasts to address past curtailments is unwarranted, whereas Applicants' forecasts are more realistic given the anticipated conditions.

Applicants' testimony includes weather design used in forecasts of weather-sensitive market segments, temperature design values for various reliability standards and gas demand forecasts (average year, cold year, peak day) for core, noncore, wholesale, and international customers.[37] Noting that Public Advocates Office Office supports their forecasts, Applicants ask the Commission to find the demand forecasts for core and noncore customers reasonable.[38]

In addition to Public Advocates Office, TURN also found most of Applicants' demand forecasts reasonable with one exception—TURN recommends a peak day load of 1,152,900 therms for the portion of the G-30 class served at medium-pressure distribution levels rather than the 996,000 therms estimated by SoCalGas.[39] TURN contends that, based on data from SoCalGas, the large commercial and industrial customers served under this schedule should have a peak day that is a weekday with 23 "heating degree days" rather than an ordinary day.[40]

SCGC submits that Applicants' peak day and cold year peak month demand forecasts for Electric Generation should be decreased by 65 percent and 21 percent, respectively, due to electric generator curtailments over the past two winters.[41] Further, SCGC alleges that the model Applicants used relied on a California Energy Commission demand forecast that did not account for Aliso and pipeline constraints.[42] As a result, SCGC contends Applicants' forecast is not

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[37] APP-02, APP-03a, APP-04, and APP-05.

[38] Applicants' Opening Brief at 28-29 and 34. *See* also Public Advocates Office Opening Brief at 3.

[39] TURN Opening Brief at 2.

[40] *Id*. at 2, citing TRN-02a at 59-62. *See* also TRN-02a Attachment 9 Data Response TURN SEU DRs 8-2.

[41] SCGC Opening Brief at 10-11.

[42] *Id*. at 3-4.

accurate.[43] SCGC requests the Commission adopt Applicants' forecast only if it lifts the Withdrawal Protocol and raises the inventory capacity from 34 to 68.6 Bcf.[44]

In response to the SCGC recommendation, TURN highlights that Aliso has been restricted for several years and the curtailments cited by SCGC did not occur until after recent pipeline outages.[45] TURN also points to a graph in SCGC's opening brief that "demonstrates that the recent price spikes did not begin until after the Line 235-2 explosion."[46]

We find that there is insufficient basis for adopting the proposal by SCGC to adjust the Electric Generation demand forecast. The significant reductions proposed by SCGC are not warranted as the curtailments did not occur until after the pipeline outages. Furthermore, according to the SoCalGas electronic bulletin ENVOY,[47] Line 235-2 returned to service on October 14, 2019 and Line 4000 returned to service at reduced pressure on October 24, 2019.[48] Additionally, Line 235-2 was again taken out of service on January 25, 2020 due to a safety-related condition but was returned to service on February 15, 2020.[49]

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[43] *Id*. at 4.

[44] *Id*. at 11.

[45] TURN Reply Brief at 2 citing Applicants Opening Brief at 30 and TRN-06 at 27-28.

[46] *Id*. at 2-3 citing SCGC Opening Brief at 31, Figure 5.

[47] Envoy is a public electronic bulletin, which can be found at: https://scgenvoy.sempra.com/index.html

[48] The Envoy maintenance schedule update can be found at: https://scgenvoy.sempra.com/#nav=/Public/ViewExternalEbb.getMessageLedger%3FfolderId%3D9%26rand%3D438

[49] SCGC Opening Comments on Proposed Decision at 4. *See* also https://sgcenfoy.sempra.com.

Applicants' demand forecast for core and non-core customer should be adopted as it represents reasonable weather design and temperature design values. As previously noted, Applicants' forecasts received support from Public Advocates Office and TURN, with one caveat. With respect to the TURN request to increase the peak day for a portion of the G-30 class, we find TURN's argument has merit based on data provided by SoCalGas and, therefore, we increase the peak day for a portion of the G-30 class.

We also adopt two uncontested elements related to this section: Unaccounted for Gas[50] and Brokerage Fee.

Applicants propose that the Unaccounted for Gas percentages provided in testimony for ratemaking purposes be updated and based on the April 2015 to March 2018 three-year average of 0.926 percent for SoCalGas and 0.565 for SDG&E.[51] No party opposes this request. Accordingly, the Commission should adopt the unaccounted-for Gas percentages and allocation factors for ratemaking purposes.

Applicants request the Commission adopt the proposed brokerage fee of 0.207 cents per therm, which is based on an updated core brokerage fee study consistent with prior cost allocation proceedings.[52] No party oppose this request. Accordingly, the Commission should adopt a brokerage fee for Applicants of 0.207 cents per therm.

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[50] Unaccounted for Gas is the difference between total receipts into SoCalGas' and SDG&E's respective service territories and total deliveries within SoCalGas' and SDG&E's respective territories. See APP-05 at 18.

[51] APP-12 at Table 16. *See* also Applicants Opening Brief at 44-45.

[52] Applicants Opening Brief at 39-40.

6.2. Allocation of Costs

Below we separately address the allocation of costs for transmission and storage and customer costs, as well as an Energy Division proposal for allocating storage.

6.2.1. Applicants' Embedded Costs Method for Transmission and Storage Functions is Reasonable with Two Modifications

We authorize Applicants to use the embedded cost method for transmission and storage functions, and we authorize the allocation of costs by customer classes as proposed by Applicants. Our comparison of Applicants' and TURN's embedded cost calculations indicates that increasing costs to the storage and transmission function, as proposed by TURN, results in an unfair shift in allocated costs from residential to noncore customers. However, we modify Applicants' method with respect to the Administrative and General (A&G) expenses and the Customer Advances for Construction (CAC) balance. We discuss the two proposals and the two modifications in depth below.

Applicants state that they prepared their embedded cost studies using the same method employed in prior cost allocation proceedings. Specifically, Applicants' embedded cost study uses 2016 recorded costs as inputs to determine how to allocate incurred costs for capital, Operations and Maintenance (O&M), and A&G expenses between the transmission and storage functions.[53] Applicants collected data from the 2016 recorded costs in SoCalGas

[53] Applicants used data from its Federal Energy Regulatory Commission (FERC) Form 2 as the basis to determine plan-in-service (capital related), O&M, and A&G expenses that are necessary to providing transmission and storage services to customers.

and SDG&E's 2016 Annual Report to the Commission. This report is also known as FERC Form 2.

Capital expenditures, O&M, and A&G transmission and storage expenses that were used in the Applicants' 2020 TCAP embedded cost study are summarized in Table 6 below.

Table 6[54]

2016 Transmission and Storage Costs ($MM)

	SDG&E	**SoCalGas**	
	Transmission	Transmission	Storage
Capital-related Costs	$24.7[55]	$126.1[56]	$71.2[57]
O&M, A&G Expenses	$15.0	$118.2	$57.5
Total	$39.7	$244.3	$128.7

As shown in Table 7 below, the combined embedded cost of backbone transmission for SoCalGas and SDG&E is $213.2 million.

[54] APP-08a at 8 and 12.

[55] Capital-related expenses for SDG&E transmission include depreciation of $9.6 million (includes $1.3 million from general plant allocated based on a labor factor of 6.2%) (APP-08 at 9), taxes of $4.7 million (transmission taxes: $22.8 x 20.2% or 4.6 million plus general plant taxes: $0.1 million) (APP-08 at 10) and return on rate base of $50.4 million (APP-08 at 9-10).

[56] Capital-related expenses for SoCalGas transmission include depreciation of $51.2 million (includes $5.5 million from general plant allocated based on a labor factor of 4.2%) (APP-08 at 2-3 and 7), taxes of $22.8 million (transmission taxes: $130.7 x 17.2% or 22.4 million plus general plant taxes: $0.4 million) (APP-08 at 4-5) and return on rate base of $52.1 million (APP-08 at Table 2).

[57] Capital-related expenses for SoCalGas storage include depreciation of $33.7 million (includes $5.5 million from general plant allocated based on a labor factor of 4.2%) (APP-08 at 2-3 and 7), taxes of $11.4 million (transmission taxes: $130.7 x 8.5% or 11.0 million plus general plant taxes: $0.4 million) (APP-08 at 4-5) and return on rate base of $26.1 million (APP-08 at Table 2).

Table 7[58] **Embedded Cost of Transmission ($MM)**					
	(A)	(B)	(C)=(A) x (B)	(D)	(E)=(C)+(D)
	SoCalGas Transmission	Backbone Transmission Percentage	SoCalGas Backbone Transmission	SDG&E Backbone Transmission	Applicant Backbone Transmission
Capital-Related Costs	$126.1	71.1%	$89.6	$24.7	$114.3
O&M, A&G Expenses	$118.2	71.0%	$83.9	$15.0	$98.9
Total	$244.3		$173.5	$39.7	$213.2

Applicants explain that, in addition to the backbone transmission cost of $213.2 million shown in Table 7, $49.2 million must be added to account for the 2018 backbone transmission balancing cost related to Pipeline Safety Enhancement Plan and Transmission Integrity Management Program. Hence, the total backbone transmission cost for Applicants is $262.4 million.

Specific to the backbone transmission cost, TURN and SCGC recommend the Commission allocate compression station operations and maintenance expenses solely to backbone transmission while Applicants maintain these expenses should be allocated to both backbone and local transmission systems. TURN and SCGC argue these expenses should be "allocated in the same manner as the compressor station capital costs" since 100 percent of compression station plant is assigned to the backbone subfunction.[59] Applicants contend the use of compression supports customers on both the backbone and local transmission systems, and explain that compressor stations are operated to provide critical functions such as moving and balancing natural gas supplies and increasing

[58] APP-08a at 14-15.

[59] TURN Opening Brief at 65 and SCGC Opening Brief at 59.

system pressures.[60] While we recognize that compressor station equipment exists on the backbone transmission system, we agree that its use also supports customers on local transmission systems. We find it reasonable to allocate compressor station operation and management expenses based on mileage to both backbone transmission and local transmission.

In addition to the embedded storage cost indicated in Table 6 above, Applicants state that SoCalGas and SDG&E will recover a revenue requirement of $32.9 million, which is associated with the cost of the Aliso Canyon Turbine Replacement, as directed in D.13-11-023.[61] Applicants explain that the $32.9 million is the average of the 2020-2022 revenue requirements based on the actual cost of $275.5 million for the Aliso Canyon Turbine Replacement.[62] Applicants maintain this results in a total embedded storage cost of $161.6 for SoCalGas during the 2020-2022 TCAP. Public Advocates Office, supported by Applicants, recommends that the Commission establish the embedded cost of storage using the revenue requirement associated with the authorized costs of $200.0 million for the Aliso Canyon Turbine Replacement project, previously approved by the Commission in D.13-11-023. Public Advocates Office explains that the remaining cost of $74.6 million ($275.5 million - $200,9 million) is being reviewed in the SoCalGas 2019 General Rate Case. In D.19-09-051, which resolved SoCalGas' 2019 General Rate Case, the Commission authorized SoCalGas to recover in rates the $74.6 million in costs that exceeded the

[60] Applicants Opening Brief at 12.

[61] APP-08 at 17.

[62] *Id*. at 18.

previously authorized amount in D.13-11-023, making Public Advocates Office' recommendation no longer relevant.

Only TURN argues against Applicants' approach to determining cost allocation for storage. Specifically, TURN opposes Applicants' use of 2016 data for the embedded cost study. TURN contends the 2016 embedded costs "reflect numerous irregularities," which "artificially reduce the results of [Applicants'] study and reassign transmission and storage costs to the distribution and customer-related functions."[63] TURN surmises this results in disproportionate recovery of storage costs from core customers.[64]

Maintaining that Applicants should have used more recent data, TURN produced its own cost allocation calculations based on using 2017 recorded FERC Form 2 data. Applicants argue that TURN's allocation process is inconsistent as TURN only updated certain segments of the 2016 embedded cost study with 2017 data.[65] Advocating for a bottom-up approach to be utilized so that all embedded costs are updated, Applicants underscore that this approach is a complicated and time-consuming exercise.[66] Otherwise, Applicants assert they would have used more recent data including the 2017 FERC Form 2 data.[67]

We decline to adopt TURN's recalculated cost allocation as we find that the process used by TURN is inconsistent. As pointed out by SCGC, using percentage escalation factors to escalate recorded costs could artificially alter the

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[63] TURN Opening Brief at 47-48.

[64] *Id*. at 48.

[65] APP-16a at 8-12. *See* also SCGC Opening Brief at 55.

[66] APP-16-a at 8-9.

[67] *Ibid*.

results of the embedded cost study and introduce error into the study.[68] Not all costs will rise proportionately; hence, we find it more precise for allocation purposes to use older recorded costs, because these are actual costs. Furthermore, we find using the Applicants' embedded cost study provides us with results that are more constant across all customer classes in comparison with the TURN proposal. As seen in Table 8 and 9 below, using the TURN proposal results in more dramatic increases for certain customer classes and inconsistent increases across customer classes.

Table 8
SoCalGas Class Average Rates
Comparisons with TURN Proposals

Utility: **SoCalGas**	**Applicants[69]**				**TURN[70]**		
Main Customer Class Rates	**Current 7/1/2018**	**Proposed 2020**	**$/therm Change**	**% Change**	**Proposed 2020**	**$/therm Change**	**% Change**
Residential	0.748	0.743	-0.005	-0.70%	$0.71	($0.04)	-5.60%
Core Commercial & Industrial (C&I)	0.325	0.380	0.056	17.10%	$0.36	$0.03	9.20%
Noncore C&I – Dist	0.077	0.084	0.008	10.10%	$0.10	$0.02	29.70%
Electric Gen (EG) - Dist, Tier 1	0.127	0.128	0.002	1.30%	$0.11	$0.03	43.30%
EG - Dist, Tier 2	0.056	0.073	0.017	30.50%			
Trans Level Service for C&I	0.024	0.032	0.008	31.20%	$0.04	$0.02	59.80%
Trans Level Service for EG	0.021	0.029	0.008	35.60%	$0.04	$0.02	70.50%

68 *See* SCGC Opening Brief at 55 citing SCG-02 at 2.

69 APP-12 at 3, Table 1R.

70 TRN-02 at 68, Table 36.

Table 9
SDG&E Class Average Rates
Comparisons with TURN Proposals

Utility: SDG&E (gas)	**Applicants[71]**				**TURN[72]**		
Main Customer Class Rates	**Current 7/1/2018**	**Proposed 2020**	**$/therm Change**	**% Change**	**Proposed 2020**	**$/therm Change**	**% Change**
Residential	$0.916	$0.926	$0.010	1.10%	$0.832	($0.083)	-9.10%
Core Commercial & Industrial (C&I)	$0.278	$0.333	$0.055	19.80%	$0.390	$0.112	40.30%
Noncore C&I – Dist	$0.117	$0.099	($0.018)	-15.40%	$0.133	$0.016	13.90%
Electric Gen (EG) - Dist, Tier 1	$0.127	$0.129	$0.002	1.40%	$0.094	$0.024	33.80%
EG - Dist, Tier 2	$0.056	$0.073	$0.017	30.80%			
Trans Level Service for C&I	$0.025	$0.032	$0.008	30.90%	$0.032	$0.008	32.60%
Trans Level Service for EG	$0.021	$0.029	$0.008	36.30%	$0.028	$0.008	38.90%

TURN also argues that Applicants arbitrarily assign 50 percent of A&G expenses to end users, *i.e.*, core customers. Applicants explain that A&G costs are allocated based on the adopted embedded cost results in the last TCAP Phase I decision, D.16-06-039. In that study, Applicants performed a two-step process where, first, 50 percent of A&G expenses were allocated to end users and, second, the remaining 50 percent were allocated to the storage and transmission functions based on labor factors determined by the percentage of total 2016 labor costs.[73] Applicants submit that this two-step process is an effort to reach a balanced allocation of a significant cost that is difficult to assign to specific

[71] APP-12 at 4, Table 2R

[72] TRN-02 at 72, Table 41

[73] Applicants Opening Brief at 91.

functional categories.[74] Furthermore, Applicants contend that if TURN's approach is adopted, 100 percent of the labor allocation of A&G expenses and general plant would be allocated to storage and transmission customers.

We find the first step of allocating half of the A&G expenses, general and common plant costs, and miscellaneous revenues to end users is arbitrary and unreasonable. Applicants provide no other logic for this two-step approach except that the approach was adopted through prior settlements, which Applicants acknowledge is not precedential.[75] Calling the two-step approach a "more even split of these costs [that] yield a more balanced and consistent allocation,"[76] Applicants provide an allocation of A&G expenses pursuant to this approach, as seen in columns A-C in Table 10 below.[77] However, with the inclusion of all A&G expenses (including the $224.2 million initially allocated to "end users") the impact of this two-step process becomes clear, as seen in column D of Table 10 below. As such, we decline to adopt the two-step approach and instead, allocate 100 percent of the A&G expenses, as well as general and common plant costs, and miscellaneous revenues, using the key factor labor percentages as indicated in column B. We use labor percentages because Applicants state that company labor is a key factor that drives A&G expenses.[78] We find this allocation to be a more balanced approach. Accordingly, we allocate SoCalGas's A&G Costs as indicated in column E, as well as general and common plant costs, and miscellaneous revenues.

[74] Applicants Opening Brief at 91 citing APP-16a at 7.

[75] APP-16a at 7.

[76] Applicants Opening Brief at 92.

[77] APP-08 at 7, Table 8.

[78] APP-08 at 7.

Similarly, SDG&E shall allocate 100 percent of the A&G expenses, as well as general and common plant costs, and miscellaneous revenuesusing SDG&E's labor factors percentages: 0.2 percent for storage and 12.4 percent for transmission.[79]

Table 10 Allocation of A&G Costs – SoCalGas					
	A	**B**	**C (B x $224.2 MM)**	**D**	**E (B x $448.4 MM)**
	Labor Costs ($MM)[80]	Labor (%)	Applicants' Proposed Allocated A&G Costs ($MM)	Applicants' Total Proposed Allocated A&G Costs ($MM)	Adopted Allocated A&G Costs ($MM)
Storage	33.7	8.4	18.8	18.8	37.6
Transmission	33.6	8.4	18.8	18.8	37.6
Distribution, Customer Accounts/Service & Information	335	83.2	186	410.9[81]	373.3
Total	402.3	100	224.2[82]	448.5[83]	448.5

As part of the 2016 Embedded Cost Study, Applicants included asset retirement obligations (ARO) in their calculation of the net book value of plant. TURN contends that AROs are not physical assets, are not included in rates, do not earn a return, and are not incremental costs that play a role in cost-based

[79] APP-08 at 11.

[80] *Id*. at 7 citing 2016 SoCalGas Form 2 at 355, lines 52-57, column b.

[81] $410.9 million = [(Column B x $224.2 million) + $224.2 million].

[82] Applicants assigned the remaining $224.2 million to end users, i.e., core customers ($448.5 million x 50 percent)

[83] SoCalGas' 2016 recorded A&G expenses plus payroll taxes. See APP-08 at 6.

ratesetting.[84] TURN asserts AROs are a product of a financial reporting requirement whereby upon removal from service assets must legally be treated as retired assets .[85]

Applicants explain that certain assets require special decommissioning, which includes an obligation to clean up the site and that obligation has a cost.[86] Supporting Applicants, SCGC underscores that AROs are as much a part of the cost of plant as the cost of pipes or valves.[87] Further, SCGC references FERC Order 631, which recognizes that when an asset is constructed, acquired, or when a legal obligation to perform a retirement activity is created, there is a liability for the fair value of an asset retirement obligation that increases the cost of the related asset. SCGC surmises it is appropriate to use the net book value of plant, including ARO, to calculate the transmission share of total net plant as a basis for functionalizing return and taxes.[88]

We find that AROs are not merely a product of a financial reporting requirement, as asserted by TURN,[89] but rather AROs are asset-related incremental costs and, hence, should be included in the embedded cost study. We deny TURN's request to omit AROs from the study.

TURN recommends the Commission assign Customer Advances for Construction (CACs) to distribution, explaining that CACs are amounts utilities collect from project developers where the hookup costs for the new project

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[84] TURN Opening Brief at 52.

[85] *Ibid*.

[86] APP-16a at 4.

[87] SCGC Opening Brief at 55.

[88] *Id*. at 56.

[89] TURN Opening Brief at 52.

initially exceed the line extension allowance. TURN highlights that Applicants allocate CAC amounts between the transmission and distribution function.[90] TURN argues that the CAC amounts should be applied entirely to distribution, because there are no CACs for transmission. While Applicants do not dispute this fact, Applicants "do not believe the impact to the embedded cost study results would be material."[91] Further, Applicants offer no additional reasoning for assigning the CAC amounts to both transmission and distribution.[92] No party disputes the fact that there are no CACs for transmission. Because we are determining policies for future cost allocation proceedings, we conclude that CAC amounts should be assigned to distribution, despite this change being immaterial in this proceeding.

In future TCAP applications, SDG&E and SoCalGas shall use the parameters we adopt here to allocate transmission and storage costs: 1) use of the most recent embedded costs from the FERC Form 2; 2) allocate compressor station operation and management expenses based on mileage to both backbone transmission and local transmission; 3) allocate 100 percent of the A&G expenses using the key factor labor percentages; 4) include AROs in the embedded cost study; and 5) assign CAC amounts to distribution.

6.2.2. A Modified Staff Proposal to Allocate Storage Costs to Core and Load Balancing Categories Is Reasonable

We adopt the Staff Proposal and its three scenarios of fluctuating inventory capacity, with the following modifications: 1) allow the proration of

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[90] *Id* at 56-57.

[91] Applicants Opening Brief at 91.

[92] *Ibid*.

daily available injection and withdrawal capacity based on the maximum authorized capacity; 2) extend the Intraday Cycle 4 (also known as Cycle 6) deadline from 9:00 pm on the gas day to 9:00 p.m. on the day following the gas day and extend the deadline for imbalance trading to 9:00 p.m. on the business day following the close of Cycle 6; 3) require Applicants to file a Tier 2 Advice Letter by the first day of the following month if the maximum allowable inventory at Aliso is revised from the current 34 Bcf; and 4) authorize SoCalGas to request modification of its storage targets through a Tier 2 Advice Letter. The modified Staff Proposal is attached to this decision as Appendix A.

As previously described above, the Staff Proposal recommends the Commission adopt a mechanism to allocate storage capacity at Aliso based on its shifting inventory capacity. The Staff Proposal advises using the embedded cost method to allocate storage costs, which applies recorded costs. (We adopt the use of the embedded cost method in Section 6.2.1 above.) In the Staff Proposal, staff recommends that the functionalized storage costs allocated to inventory, injection, and withdrawal be subsequently apportioned to core and balancing functions based on storage capabilities or modified as necessary if Aliso's maximum allowable inventory changes. The Staff Proposal also recommends eliminating the proposed reliability function and maintaining the Unbundled Storage Program but limiting it to the Increased Scenario only, whereby additional inventory is allocated to the program if inventory capacity reaches 92.5 Bcf or higher.

Parties support the Staff Proposal to varying degrees and offer modifications.[93] Applicants and TURN are reluctant supporters. Applicants maintain their proposal provides a reasonable basis for allocating costs but acknowledge the rationale behind the Staff Proposal, given the current storage constraints.[94] Similarly, TURN contends the best outcome would be for the Commission to allow full use of Aliso until the current pipeline delivery limitations are corrected but until then the Staff Proposal is the least worst outcome.[95] At the other end of the spectrum, both SCGC and Indicated Shippers support the Staff Proposal and the mechanism as a means to address fluctuating storage inventory, but both entities also offer modifications.[96]

We find the Staff Proposal for storage allocation best meets the needs of a fluctuating storage inventory. However, the Staff Proposal should be modified in response to party comments. We address all modifications individually below.

We begin with the topic of withdrawal capacity. The Staff Proposal states that it is essential to consider the actual total withdrawal capacity for the winter and summer seasons when allocating storage amounts. Proposing to allocate two different withdrawal figures to core customers and the balancing account,

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[93] Applicants Opening Comments on Staff Proposal, October 24, 2019 at 1 and 3-4, SCE Opening Comments on Staff Proposal, October 24, 2019 at 2, Indicated Shippers Opening Comments on Staff Proposal, October 24, 2019 at 2, TURN Opening Comments on Staff Proposal, October 24, 2019 at 2.

[94] Applicants Opening Comments on Staff Proposal, October 24, 2019 at 1.

[95] TURN Opening Comments on Staff Proposal, October 24, 2019 at 2.

[96] Indicated Shippers Opening Comments on Staff Proposal, October 24, 2019 at 2 and SCGC Opening Comments on Staff Proposal at 2-3.

the Staff Proposal asserts this accounts for the impact of the Withdrawal Protocol.

In comments to the Staff Proposal, Applicants clarify that "SoCalGas does not expect to be at maximum inventory levels system-wide during the peak demand periods of December through February, therefore withdrawal capability will not be at the maximum rates.[97] Applicants caution that actual withdrawal capacity will decrease over the course of a winter and injection capacity will become limited when Aliso is at maximum authorized inventory and, as a result, balancing will receive first priority and core customers will receive diminished rights as winter progresses.[98] Recommending the Commission remove the Rule No. 30 requirement that the daily balancing function receive first priority to withdrawal, Applicants suggest the Commission authorize a daily prorating of the available injection and withdrawal capacity allocated to core customers and the balancing function.[99] Applicants contend this will better maintain cost causation and consistency.[100]

Prorating daily available injection and withdrawal capacity, based on the maximum authorized capacity, should be adopted as it should lead to a proportionate reduction of withdrawal and injection capacity based on customer cost allocation shares. Other parties voiced concern that withdrawal capacity will not be available consistently throughout the year, especially during the

[97] *Id*. at 2.

[98] *Id*. at 5.

[99] *Ibid*. *See* also TURN Reply Comments on Staff Proposal, October 31, 2019 at 1.

[100] Applicants Opening Comments on Staff Proposal, October 24, 2019 at 3-4.

winter when storage inventory may likely be below field capacity.[101] TURN and Indicated Shippers support Applicants' proposal to replace the Rule 30 provision that gives Load Balancing a higher priority than Core Reliability with the daily prorating because it provides core customers with similar protections as the Staff Proposal, for injection and withdrawal capacity.[102]

While recognizing the overstatement of capacity in the Staff Proposal, SCGC asserts core reliability and load balancing capacity allocations in Table 1 of the proposal should be modified. As pointed out by Applicants, the capacities provided by SCGC are lower than those proposed by Applicants and in Table 1 of the Staff Proposal, but not proportionately. We agree with Applicants that the percentage allocations in the Staff Proposal better reflect the operational needs of each function.[103]

Accordingly, we modify the Staff Proposal to allow a daily proration of the injection and withdrawal capacity allocated to core customers and the balancing function, based on the available injection and withdrawal capacities. We recognize that as inventory in a gas storage field declines, its corresponding withdrawal capacity is reduced. We also recognize that injection capacity tends to decrease as storage fields become full. The withdrawal capacity allocation in Tables 1 and 2 above is based on the maximum withdrawal capacity available when storage fields are closer to full. Hence, the withdrawal capacity allocated to core customers and the balancing function in Tables 1 and 2 shall be prorated

[101] TURN Reply Comments on Staff Proposal, October 31, 2019 at 1. *See* also SCGC Opening Comments on Staff Proposal, October 24, 2019 at 6-7.

[102] TURN Reply Comments on Staff Proposal, October 31, 2019 at 2 and Indicated Shippers Reply Comments on Staff Proposal, October 31, 2019 at 5.

[103] *See* Applicants Reply Comments on Staff Proposal, October 31, 2019 at 3.

daily based on the available withdrawal capacity. The injection capacity allocation in Tables 1 and 2 is based on maximum injection capacity available. Thus, the injection capacity allocated to core customers and the balancing function in Tables 1 and 2 shall be prorated daily based on the available injection capacity. We clarify that this would eliminate the guarantee of core customers receiving 100 MMcfd or 50 percent of total injection capacity, whichever is lesser, under all three scenarios.

We also address proposals to extend the Cycle 6 deadline from 9:00 pm on the Gas Day to 9:00 p.m. on the day following the Gas Day and extend the deadline for imbalance trading to 9:00 p.m. on the business day following the close of Cycle 6. Applicants contend that the Staff Proposal, as currently written, would limit Gas Acquisition's ability to optimize its storage injections to minimize exposure to OFO penalties in light of a new balancing regime. Explaining that D.19-08-002 requires Applicants to balance core deliveries to estimated actual consumption instead of a forecast beginning on April 1, 2020, Applicants underscore that the decision cautions that this requirement may provide an incentive to Applicants to avoid high OFO penalties by bringing in less gas that it would have under the current forecasting process, which "could lead to reliability problems such as curtailments and market disruptions this coming winter."[104]

D.19-08-002 did not adopt the mitigation measure Applicants proposed in that proceeding because "issues regarding imbalance trading are being

[104] Applicants Opening Comments to the Staff Proposal, October 24, 2019 at 9 citing D.19-08-002 at 27.

considered in [A.18-07-024]."[105] Applicants explain that opening briefs in this proceeding had already been filed and did not previously include its proposed recommendation. Applicants, therefore, request that the Commission consider in this proceeding the adoption of an amendment of SoCalGas Rule 30 to extend Intraday Cycle 4, also known as Cycle 6, from 9:00 pm on the Gas Day to 9:00 a.m. on the day following the Gas Day. Applicants contend this amendment could partially address the concern of curtailments and market disruptions due to bringing in less gas than it otherwise would have prior to the new requirement. D.19-08-002 notes that SCGC supported the amendment based on the condition that the deadline for imbalance trading is also "extended to 9:00 am on the business day following the close of Cycle 6."[106] In reply comments to the Staff Proposal, TURN expresses support for both amendments.[107] While neither opposing nor supporting Applicants' request, Indicated Shippers state if the Commission approves the request, the SCGC amendment should be adopted.

We find both amendments to SoCalGas Rule 30 to be reasonable as they should provide an improved opportunity to cure imbalances. Accordingly, we amend SoCalGas Rule 30 to extend Intraday Cycle 4 (also known as Cycle 6) from 9:00 pm on the Gas Day to 9:00 p.m. on the day following the Gas Day and the imbalance trading is extended to 9:00 p.m. on the business day following the close of Cycle 6.

We turn to the request for the Commission to provide further direction on the process by which customer rates would change in the Staff Proposal. In

[105] *Id*. at 10 citing D.19-08-002 at 26.

[106] *Id*. at 9 citing D.19-08-002 at 25.

[107] TURN Reply Comments to the Staff Proposal, October 31, 2019 at 2.

comments to the Staff Proposal, Applicants, Indicated Shippers, and TURN request additional Commission direction while offering proposed changes to the process used to change customer rates if the Commission adopts the Staff Proposal. Applicants propose that because allocated costs for the various outcomes identified in the Staff Proposal are similar, the Commission should authorize SoCalGas to update its transportation rates, if necessary, as part of an otherwise scheduled rate change. TURN submits that an advice letter process with supporting workpapers would provide the necessary transparency in such a process and suggests the advice letter could be submitted at the beginning of the month following any change to the maximum allowable Aliso inventory capacity.[108] Indicated Shippers agree that parties should be allowed to analyze and comment on any SoCalGas allocation prior to its adoption to ensure its accuracy and efficacy.[109]

Applicants contend their approach will help with rate stability and planning for customers and reduce the administrative burden for Applicants and the Commission.[110] TURN does not oppose Applicants' approach but suggests the Commission establish a threshold whereby a cost allocation change of $5 million or more should trigger a rate change even if there is not another scheduled one upcoming.[111] Indicated Shippers contend that deferring transportation rate changes would be inconsistent with the Commission's intent

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[108] TURN Opening Comments on Staff Proposal, October 24, 2019 at 7

[109] Indicated Shippers Opening Comments on Staff Proposal, October 24, 2019 at 7.

[110] Applicants Opening Comments on Staff Proposal, October 24, 2019 at 7 and Applicants Reply Comments on Staff Proposal, October 31, 2019 at 8.

[111] TURN Reply Comments on Staff Proposal, October 31, 2019 at 2.

to eliminate the "incongruence between the TCAP allocations and reality" as expressed in D.17-11-021.[112]

We recognize the efficiency in Applicants' proposal to incorporate any necessary update to transportation rates as part of an otherwise scheduled rate change. With respect to the concern of the incongruence referenced by Indicated Shippers, we find that cost allocations should not change dramatically and thus the concern is minimal. Accordingly, the Commission should authorize Applicants' proposal. However, a threshold of a $5 million cost allocation change, as suggested by TURN, should address any incongruence between the TCAP allocation and reality, as previously expressed in D.17-11-021. Accordingly, if the $5 million cost allocation change threshold is met, SoCalGas shall submit a Tier 2 Advice Letter by the 15th of the month following such a change. The Advice Letter shall provide allocated costs and illustrative class-average rate changes and related work papers. For changes to cost allocation of less than $5 million, SoCalGas may update its transportation rates as part of its next scheduled January 1 consolidated rate change.

Lastly, we address storage target modifications. Applicants request that, if the Staff Proposal is adopted, the Commission authorize SoCalGas to seek modification of its storage targets by a Tier 2 Advice Letter as a compliance item.[113] Applicants explain that the SoCalGas' Gas Cost Incentive Mechanism Preliminary Statement requires that the annual storage inventory target on November 1 is 83 Bcf and, if the target is not attained, a minimum of 69 Bcf must

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[112] Indicated Shippers Reply Comments on Staff Proposal, October 31, 2019 at 7-8 citing D.17-11-021 at 9.

[113] Applicants Opening Comments to the Staff Proposal, October 24, 2019 at 18.

be reached by December 1.[114] Applicants assert that because the Staff Proposal allocates the core 74.6 Bcf, the November 1 target is not possible unless Aliso inventory is sufficiently increased and requests to modify the target through an advice letter.[115]

Applicants' request is reasonable. We acknowledge the Staff Proposal results in a ten percent reduction from the 83 Bcf currently allocated to bundled core customers. Hence the November 1 target of 83 Bcf is not possible. SoCalGas should be authorized to modify its storage inventory targets by submitting a Tier 2 Advice Letter no later than 90 days after issuance of this decision.

As described below, all other requested modifications to the Staff Proposal are denied.

Both Applicants and TURN discuss the Aliso Withdrawal Protocol, which we describe above in Section 4. Applicants request the Commission authorize SoCalGas to use Aliso to manage inventory levels throughout the year, maintain reasonable levels in non-Aliso fields, and provide an increased margin of safety for system reliability.[116] Applicants assert the Staff Proposal should address the nature of how the Withdrawal Protocol impedes injections.[117] Similarly, TURN calls for the Commission to allow the full use of Aliso until the current pipeline delivery limitations are corrected.[118] We decline to approve these requests. Changes to the Withdrawal Protocol are not in the scope of this proceeding and should not be considered by the Commission in this proceeding.

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[114] *Ibid.*

[115] *Ibid.*

[116] Applicants Opening Comments on the Staff Proposal, October 24, 2019 at 14.

[117] *Ibid.*

[118] TURN Opening Comments on the Staff Proposal, October 24, 2019 at 2.

Relatedly, Applicants request the Commission to remove the core limitations to only purchase firm pipeline receipt contracts of up to 120 percent of annual average throughput. Consideration of such limitations are also not in the scope of this proceeding and should not be considered by the Commission.

The Staff Proposal recommended to continue the Unbundled Storage Program if the capacity exists and retain the existing sharing mechanism. Applicants request to modify the Staff Proposal to remove the sharing mechanism associated with the Unbundled Storage Program. Applicants contend that if a limited amount of storage inventory for noncore customers is needed, the sharing mechanism, "which was adopted under very different circumstances, is not integral to that need."[119] Applicants explain that the prior agreement for an Unbundled Storage Program was a mutual endeavor, under much different operational conditions. Further, Applicants maintain that the Staff Proposal is not aligned with Applicants' goal to dedicate storage assets to provide system reliability and, therefore, the sharing mechanism should not be continued.[120]

The Indicated Shippers, SCGC, and TURN urge the Commission to retain the Unbundled Storage Program with the sharing mechanism in place, if capacity is available. As noted by the Indicated Shippers, the Staff Proposal states the Unbundled Storage Program is pivotal for meeting noncore customer needs in periods of high demand.[121] Indicated Shippers allege that Applicants' opposition to the sharing mechanism is an attempt to eliminate shareholders' market storage

[119] Applicants Opening Comments to the Staff Proposal, October 24, 2019 at 8.

[120] *Ibid*.

[121] Indicated Shippers Reply Comments to the Staff Proposal, October 31, 2019 at 6. *See* Staff Proposal at 13.

risk and costs while transferring all liability and storage costs to ratepayers.[122] Similarly, SCGC supports retaining the sharing mechanism because it would result in shareholders and ratepayers benefiting from net revenues that result from the sales of Unbundled Storage Program capacity.[123]

While we agree that retaining the sharing mechanism is not necessary for overall system reliability purposes, as argued by Applicants, we find the sharing mechanism provides a balanced and fair approach for risk and reward sharing between shareholders and ratepayers. Accordingly, we deny the request to eliminate the sharing mechanism. Applicants shall follow the storage allocations provided in the modified Staff Proposal in Appendix A of this decision.

6.2.3. Applicants Are Authorized to Use the Long Run Marginal Cost Method with the Rental Method

We authorize Applicants to use the LRMC Method and the Rental Method to determine cost allocation by customer classes. We deny the request by Public Advocates Office to order Applicants to update their TCAP cost studies with 2018 recorded data as the update would not materially affect one customer class over another. As discussed below, we find neither the Rental Method nor the New Customer Only Method to be perfect approaches to determine marginal customer-related capital costs. However, we find the results of the Rental Method provide the Commission with a reasonable outcome that presents a fair balance across customer classes. We also adopt several TURN recommendations, as discussed below.

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[122] *Id*. at 6-7.

[123] SCGC Reply Comments to the Staff Proposal, October 31, 2019 at 8-9.

Both SDG&E and SoCalGas propose to derive the cost allocations for the customer-related and medium- and high-pressure distribution-related functions using the LRMC method. For this TCAP cycle (2020-2022), Applicants updated the LRMC study presented in prior TCAPs to reflect actual costs and allocations based on 2016 activities. The costs were then escalated to 2020 dollars to reflect Applicants' costs for the first year of the new TCAP cycle.

Public Advocates Office requests the Commission to order Applicants to update the LRMC study with 2018 data to include the effects of the Tax Cut and Jobs Act, which Public Advocates Office contends will secure the intended benefits of the Act and the cost of capital adjustments for ratepayers.[124] We deny this request. The effects of the Act will be across all customer classes and should not materially impact one class over the other.

Applicants describe the LRMC of a service as the incremental cost to serve one additional unit in the long run, referred to as the marginal unit cost.[125] Customer-related costs include capital and O&M expenses incurred to provide customer access to the gas supply system.[126] Medium-pressure and high-pressure distribution costs include the building and maintenance costs of systems that deliver gas from the transmission system to customer load centers.[127]

Applicants explain that the LRMC-based functional revenue is derived by multiplying the LRMC by the number of marginal demand measures also known

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[124] Public Advocates Office Opening Brief at 18-19.

[125] APP-09 at 3 and APP-10 at 2.

[126] APP-09 at 4 and APP-10 at 3.

[127] *Ibid*.

as the cost causation unit.[128] For both utilities, the marginal demand measure for customer-related costs is the number of customers and is developed using the Rental Method. SoCalGas and SDG&E maintain the Rental Method accurately estimates the cost of providing an additional customer with the access to gas service (*i.e.*, the marginal capital related customer cost.)[129] The Rental Method assigns the real level annualized cost of a new final line transformer, service drops and meter to all customers and reflects the annualized capital cost of hooking up an additional customer.[130] Marginal customer capital cost under the Rental Method equals the change in total capital cost divided by the change in one additional customer. For medium-pressure distribution-related and high-pressure distribution-related costs, the marginal demand measure is peak day demand and peak month demand, respectively. These are forecasted using a linear regression analysis that predicts cumulative marginal investment as a function of cumulative marginal peak-day demand.[131]

Generally, parties support the use of the LRMC method to allocate customer-related, medium-pressure and high-pressure distribution-related costs. The major contention in this issue is the use of the Rental Method versus the New Customer Only Method to calculate marginal customer costs. We first focus our discussion on this issue and then address other recommended revisions as well.

The Rental Method establishes the marginal customer cost by assigning the real level annualized cost of a new final line transformer, service drop, and

[128] *Ibid*.

[129] *Ibid*. *See* also APP-12 at 10.

[130] *Ibid*.

[131] *Ibid*.

meter[132] to all customers. The New Customer Only Method establishes the marginal customer cost by assigning the net present value of the final line transformer, service drop and meter revenue requirement over its service life to new customers only. Parties opposing the Rental Method contend it overstates the price for the final line transformer, service drop and meter. Parties opposing the New Customer Only Method contend it creates undercollection and results in all other customers subsidizing residential customers.

TURN and Public Advocates Office recommend the Commission require the use of the New Customer Only Method and cite to prior Commission support for its use in D.95-12-053 and D.96-04-05. The New Customer Only Method assigns the net present value of a final line transformer, service drop and meter revenue requirement over its service life (also referred to as the full cost of a new TSM set) to new customers only. The New Customer Only Method customer capital cost equals the change in total capital cost for all new customers divided by all existing and new customers.[133] According to Public Advocates Office, the Commission previously adopted New Customer Only Method versus the Rental Method because the "Rental Method overstates the price that would prevail in a competitive market by assuming that none would be allowed to purchase their hook-up"[134] and the Rental Method does not produce a competitive price for customers hookups.[135]

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[132] This is referred to by some parties as TSM and others as SRM (service lines, regulators, and meters.)

[133] APP-12a at Appendix B, Slide 3.

[134] Public Advocates Office Opening Brief at 14 citing D.950120953 at Finding of Fact No. 17.

[135] *Id*. citing D.96-04-050 at Finding of Fact No. 37.

Applicants, CSU, Indicated Shippers, SCGC, and California Manufacturers & Technology Association support the Rental Method, contending it is more appropriate because the New Customer Only Method does not accurately capture cost causation. For example, Indicated Shippers assert that the Rental Method considers all costs required to hook up all of the customers, whereas the New Customer Only Method ignores the costs associated with the 99 percent of customers who are already being served.[136] Furthermore, Indicated Shippers contend that because the customer cost of serving residential customers is understated, the New Customer Only Method results in an unfair balance of costs shifted to commercial and industrial customers.[137]

As discussed below, we find that neither the Rental Method nor the New Customer Only Method are optimal approaches to determining marginal costs. However, the results of the Rental Method provide the Commission marginal costs with less dramatic increases across all customer classes, thus avoiding disproportionate rate impacts to customer classes with few new customers. The use of the Rental Method in this proceeding will result in the most reasonable revenue allocation and near cost-based rates for SoCalGas and SDG&E customers.

The Commission has stated that its objective in designing and setting rate structures is to base the design and structure on marginal cost and cost-causation principles.[138] Marginal customer cost is the cost of providing service to an

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[136] ISH-04 at 9-10.

[137] *Ibid*.

[138] APP-12 at 9 citing D.17-09-035 at 18.

additional customer.[139] As noted by Applicants, cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs.[140] We agree that the essential element in the selection of a reasonable cost allocation method is the establishment of relationships between customer requirements, load profiles and usage characteristics, and the costs incurred by the utility in serving those requirements.[141]

In the past, the Commission has supported both methods for varying reasons. Parties discuss the Commission support of the Rental Method in D.92-12-058, while parties opposing the Rental Method discuss Commission support of the New Customer Only Method in D.95-12-053. Most recently, in D.19-10-036, the Commission adopted a marginal cost study based on the Rental Method, stating that it "will result in the most reasonable revenue allocation and the most reasonable cost-based rates" for customers.[142] The Commission found that the use of the Rental Method would "produce results that are fair across customer classes" and would "avoid disproportionate rate impacts to customer classes that have few new entrants."[143]

In this review of the two methods, we are faced with the same arguments that these parties have presented in prior proceedings. Supporters of each approach contend their preferred approach most accurately captures marginal capital related customer cost. We find that neither side fully validates the use of its preferred model but rather focuses on invalidating the opposing model.

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139 *Ibid*.

140 APP-09 at 2 and APP-10 at 2.

141 *Ibid*.

142 D.19-10-036 at 32-33.

143 *Id*. at 32.

Hence, we are left with two imperfect models. However, in looking at the results of the models, we find the Rental Method results in costs that are fair across the customer classes, as seen in Tables 11 and 12 below.

Table 11
SoCalGas Class Average Rates *(Illustrative)*
Rental Method and New Customer Only Method Comparisons

Utility: SoCalGas	**SoCalGas[144] (Rental Method)**				**Public Advocates Office[145] (New Customer Only Method Without Replacement Cost Adder)**		
Main Customer Class Rates	**Current 7/1/2018**	**Proposed 2020**	**$/therm Change**	**% Change**	**Proposed 2020**	**$/therm Change**	**% Change**
Residential	0.748	0.743	-0.005	-0.70%	0.73	-0.02	-2.20%
Core Commercial & Industrial (C&I)	0.325	0.380	0.056	17.10%	0.37	0.05	14.40%
Noncore C&I - Dist(ribution)	0.077	0.084	0.008	10.10%	0.10	0.02	28.70%
Electric Gen (EG) - Dist, Tier 1	0.127	0.128	0.002	1.30%	0.17	0.04	33.00%
EG - Dist, Tier 2	0.056	0.073	0.017	30.50%	0.08	0.03	48.90%
Trans Level Service for C&I1	0.024	0.032	0.008	31.20%	0.03	0.01	28.50%
Trans Level Service for EG2	0.021	0.029	0.008	35.60%	0.03	0.01	32.50%

144 APP-12 at 3.

145 PAO-12 at 4.

Table 12
SDG&E Class Average Rates *(Illustrative)*
Rental Method and New Customer Only Method Comparisons

Utility: SDG&E	**SDG&E[146] (Rental Method)**				**Public Advocates Office[147] (New Customer Only Method Without Replacement Cost Adder)**		
Main Customer Class Rates	**Current 7/1/2018**	**Proposed 2020**	**$/therm Change**	**% Change**	**Proposed 2020**	**$/therm Change**	**% Change**
Residential	0.916	0.926	0.010	1.10%	0.864	-0.052	-5.70%
Core C&I	0.278	0.333	0.055	19.80%	0.406	0.127	46.10%
Noncore C&I - Dist(ribution)	0.117	0.099	-0.018	-15.40%	0.135	0.017	15.30%
Electric Gen (EG) - Dist, Tier 1	0.127	0.129	0.002	1.40%	0.178	0.051	40.1%
EG - Dist, Tier 2	0.056	0.073	0.017	30.80%	0.086	0.030	53.9%
Trans Level Service for C&I1	0.025	0.032	0.008	30.90%	0.032	0.007	29.5%
Trans Level Service for EG2	0.021	0.029	0.008	36.30%	0.029	0.007	34.7%

The Commission should authorize the use of the LRMC for allocating customer costs and use the results of the Rental Method as indicated in Tables 11 and 12 above. Given that neither the Rental Method nor the New Customer Only Method is perfect, we require Applicants to continue to provide results in future TCAP applications using the four approaches, as previously directed in D.17-09-035. The Commission will continue to compare the results of the four approaches until such time the Commission develops and adopts an improved approach.

We also adopt four recommendations with respect to the LRMC Method: 1) allocate SoCalGas's large commercial and industrial and economic development costs only to tariff Schedule G-10 large customers; 2) modify the High-Pressure Distribution allocation rate for SDG&E's measurement and

[146] APP-12 at 4.

[147] PAO-12 at 6.

regulating station O&M; 3) include the erroneously omitted $3.1 million in service line O&M costs; and 4) adopt the TURN proposed adjustments to the cathodic protection costs for SDG&E. We address each of these issues individually below.

Applicants propose that large commercial and industrial and economic development program costs for SoCalGas be allocated to all SoCalGas Schedule G-10 customers. TURN recommends that the large commercial and industrial and economic development program costs be allocated only to large and very large G-10 customers, because this complies with SoCalGas's own cost allocation.[148] Applicants do not oppose this recommendation.[149] We consider this an oversight by Applicants and adopt TURN's recommended modification.

Applicants' LRMC study for SDG&E's customers applied the same ratio of line miles to measurement and regulating stations as it did to main stations, which resulted in an allocation of 4.4 percent of the O&M costs to high pressure distribution. TURN contends that because 10 percent of SDG&E's measurement and regulating stations are related to the interface between transmission and high pressure distribution pipelines, the Commission should increase the high pressure distribution O&M cost allocation for measurement and regulating stations to 10 percent.[150] Applicants accept this adjustment in rebuttal testimony.[151] We find the 10 percent cost allocation aligns with the percentage of measurement and regulating stations related to transmission and high pressure distribution pipelines and should be adopted.

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[148] TURN Opening Brief at 97-98 citing TRN-02a at 45.

[149] APP-17a at 8.

[150] TURN Opening Brief at 99.

[151] *Id*. at 99 citing APP-17 at 7, which is now APP-17a at 8.

Applicants' LRMC study included an estimate of service line O&M costs of $13.1 million, which was subsequently identified in a data request response as $16.2 million.[152] TURN recommends the Commission adopt the corrected amount. Applicants agree with the recommendation.[153] The service line O&M cost of $16.2 is a corrected amount and should be adopted as such.

With respect to the LRMC study, TURN requests a modification related to SDG&E's cathodic protection costs. Applicants' LRMC study includes a method for calculating cathodic protection costs that results in SDG&E allocating more cathodic protection costs for services than the total amount spent on cathodic protection. TURN alerted Applicants of this error and recommended an updated method using direct cathodic protection costs and allocation based on only cathodically protected miles as opposed to all miles.[154] Applicants do not oppose the TURN recommendation.[155] Given that this new calculation method results in an output that no one disputes, we find it reasonable to adopt the use of the method and its results.

6.2.4. Applicants Should Modify the Self-Generation Incentive Program Cost Allocation

We approve Applicants' Self-Generation Incentive Program (SGIP) cost allocation proposal but modify it to address concerns that 92 percent of costs are allocated to Electric Generation customers, who are explicitly excluded from

[152] TURN Opening Brief at 95 citing TRN-02a at 43.

[153] APP-17a at 8.

[154] *Id*. at 9.

[155] *Ibid*.

participating in the SGIP.[156] As described below, we modify the proposal such that 50 percent of the SGIP costs are allocated to the host customer class and 50 percent of the SGIP costs are allocated to the receiving customer class. We find that this modification spreads the costs of the SGIP across a larger body of ratepayers, decreasing the rate impact for any single ratepayer group. The modified solution allows customers receiving SGIP benefits to continue participating in the funding of SGIP and addresses ambiguities in the SGIP decision and resolution.

We begin with a brief description of the SGIP, which provides incentives to support existing, new, and emerging distributed energy resources. The California legislature created SGIP to address peak electricity problems facing California at a time when California was experiencing rolling blackouts that left thousands of residential electricity customers and businesses in Northern California without power.[157] SGIP provides rebates for qualifying distributed energy resources installed on the customer's side of the utility meter.[158] The program is intended to encourage installation of several types of self-generation technologies, both renewable and non-renewable. Costs are currently allocated across all customer classes based on equal centers per therm. However,

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[156] Indicated Shippers Opening Brief at 39 citing the SGIP Handbook which is included in Exhibit SCG-01, Schedule S at 28:13-17.

[157] Assembly Bill 970 (Stats. 2000, Ch. 329), signed by the Governor on September 6, 2000 established Public Utilities Code Section 399.15(b), directed the Commission to develop self-generation initiatives.

[158] Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, and advanced energy storage systems. (*See* https://www.cpuc.ca.gov/sgip/.)

Resolution E-4926 now requires the allocation of SGIP funds to be based on program participation over the previous years.[159]

Applicants propose to re-allocate the contribution of customer classes to the SGIP by totaling the incentives awarded in the most recent three years and allocate funds based on the percentage of incentives disbursed to each class.[160] Tables 13 and 14 provide a comparison of the current and proposed SGIP cost allocation percentages.

Table 13
SoCalGas SGIP Cost Allocation

Class	**3-year Total Incentives Paid**	**Current % Allocation**	**Applicants' Proposed % Allocation**
Residential	$38,488	25.9%	0.1%
Core C&I	$356,733	10.9%	1.3%
Noncore EG	$28,023,417	28.4%	98.6%
Other Noncore	$0	32.9%	0.0%
Other Core	$0	1.9%	0.0%
Total	**$28,418,597**	**100.0%**	**100.0%**

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[159] APP-12 at 26, citing E-4926 at 18, Finding 4.

[160] *Id*. at 26.

Table 14[161] SDG&E SGIP Cost Allocation			
Class	**3-year Total Incentives Paid**	**Current % Allocation**	**Applicants' Proposed % Allocation**
Residential	$34,564	85.7%	0.4%
Core C&I	$7,259,875	11.0%	91.3%
Noncore EG	$660,000	2.0%	8.3%
Other Noncore	$0	0.9%	0.0%
Other Core	$0	0.4%	0.0%
Total	**$7,954,439**	**100.0%**	**100.0%**

Most parties oppose this allocation and contend that the allocation does not comply with the directives set by the Commission in D.16-06-055, which requires "equitable distribution of the costs and benefits,"[162] and Resolution E-4926, which requires allocation on the "basis of the actual benefits resulting from the disbursement of program incentives over the previous three years in its service territory."[163] SCGC highlights that Applicants' proposal would allocate 92 percent of SGIP costs to Electric Generations, which are explicitly prohibited from receiving any SGIP incentives.[164] SCGC contends Applicants' proposal "violates the Commission's clear direction to allocate costs on the basis of actual participation in the SGIP program."[165] SCGC maintains that the proposed "allocation was based on the rate schedule the Host Customer's power generation project is placed on after the project is completed rather than the rate schedule the Host customer was on at the time

[161] APP-12 at 27.

[162] D.16-06-055 at Ordering Paragraph 4.

[163] E-4956 at Ordering Paragraph 3a.

[164] SCG-01 at 30-31.

[165] SCGC Opening Brief at 45.

that the Host customer received the SGIP incentive payments."[166] Agreeing with SCGC, TURN argues that this approach results in the allocation of SGIP costs primarily to the noncore electric generation customers that by their very nature are prohibited from receiving payments.[167] The City of Long Beach (City) adds that the wholesale customer class would indirectly pay for SGIP costs, given certain rate design technicalities, despite not receiving any program incentives.[168]

SCGC proposes an SGIP cost allocation alternative, which allocates zero percent to noncore Electric Generation customers and a majority of the cost to the Core Commercial and Industrial customer class. Specifically, SCGC recommends that Applicants only recover costs from the GT-TLS (GT-3) and commercial/industrial subclass to prevent inadvertent recovery from the other sub-classes served under the GT-TLS scheduled.[169] SCGC contends this allocation is feasible and performed for greenhouse gas related costs.[170]

Applicants maintain their allocation proposal follows the letter of what is contained in D.16-06-055 and Resolution E-4956, in that SGIP costs should "be allocated based on class of customers participating, not by sub-class."[171] Further, Applicants assert that the Commission did not intend that only the customers eligible to participate should pay for the program, which would result in a self-

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[166] *Id*. at 45-46.

[167] TURN Opening Brief at 104 citing TRN-06 at 27. See also Indicated Shippers Opening Brief at 38-40.

[168] City of Long Beach Opening Brief at 40-41.

[169] SCGC Opening Brief at 51-52.

[170] SCGC Opening Brief at 52 citing SCG-01a at 34-35.

[171] Applicants Opening Brief at 103.

funding program where only customers receiving the SGIP payments are funding the SGIP program.[172]

To address the concerns of SCGC, Applicants suggest a hybrid solution, which would divide the SGIP costs in half and allocate half to the host customer class and half to the receiving customer class. Applicants maintain this "would spread the costs among a larger body of ratepayers (thus decreasing the rate impact for any single ratepayer group)."[173] SCGC argues the hybrid approach is a subsidization of the SGIP by customers ineligible to receive SGIP incentives and conflicts with the intent of Resolution E-5927.[174]

We find neither Applicants' proposal nor SCGC's proposal to be an equitable distribution of the costs and benefits of the SGIP. We agree that Applicants' proposal places a majority of the cost responsibility on the Core Commercial and Industrial customers(91.3 percent for SDG&E) and on the noncore Electric Generation customers (98.6 percent for SoCalGas), a large portion of whom are not eligible for incentives (307 out of 396 SoCalGas customers and 53 out of 93 SDG&E customers).[175] However, with respect to the SCGC proposal, we are concerned that the 129 out of 428 customers who have received SGIP incentives would not contribute in an equitable fashion to the SGIP costs.[176] While we recognize that the hybrid approach is not a perfect approach, we find that the hybrid approach represents the most equitable distribution of the costs and benefits, at this time. In response to the SCGC

[172] *Id*. at 104.

[173] APP-18a at 29.

[174] SCGC Opening Brief at 54.

[175] Evidentiary Hearing Transcript, Volume 5 at 42 to 56.

[176] *Ibid*.

allegation of subsidization by ineligible customers, we point to the correct statement by Applicants: to offer an incentive, utilities must collect the funds from a larger pool of customers than simply those that receive an incentive and, thus, some of the costs of the incentive program are borne by those not participating in the actual program. The Commission should adopt Applicants' hybrid approach to allocate SGIP costs.

Resolution E-4926 requires the effective SGIP cost allocation factors to be updated each year based on the actual benefits resulting from the disbursement of program incentives over the previous three years. The updated allocations will be presented for approval in Applicants' Regulatory Account Update Advice Letter submissions annually in October.

Lastly, we address the SGIP cost allocation concern raised by the City. The City asserts that, despite not being allocated costs directly under the Applicants' proposal for SoCalGas customers, some SGIP costs allocated to other transmission-level service customer classes will be collected by the City through the system-wide transmission-level service rate. The City explains that transmission-level service includes noncore electric generation served at the transmission level, which is allocated 85.9 percent of the SGIP costs.[177] As a result, the City will pay approximately $45,000 of the SGIP costs.[178] Maintaining recovery of SGIP costs from the City conflicts with Commission and state policy, the City requests the Commission to revise the rate design such that SGIP costs are recovered consistent with Commission policy in Resolution E-4956. In

[177] LGB-01 at 3-22 and Table 5. Table 5 indicates that Noncore Electric Generation: Transmission customers are allocated 85.9 percent and Noncore Electric Generation: Distribution customers are allocated 12.7 percent, which totals 98.6 percent.

[178] *Ibid*.

response, Applicants agree with the City's assessment, explaining that the rate design process combines costs from several transmission level service rate classes to generate a service-territory wide rate, resulting in SGIP costs to be allocated to wholesale customers.[179] Applicants agree to exclude SGIP costs from wholesale customer rates.

Resolution E-4926 underscores that pursuant to Public Utilities Code Section 379.6(a)(1), the Commission must ensure "an equitable distribution of the costs and benefits" of SGIP.[180] Hence, E-4926 required SDG&E and SoCalGas to file proposals to "allocate costs on the basis of the actual benefits resulting from the disbursement of program incentives over the previous three years."[181] We agree that the current method employed by Applicants for SoCalGas customers inappropriately recovers SGIP costs from wholesale customers. Accordingly, Applicants should revise the method such that wholesale customers are not responsible for SGIP costs.

6.3. Transportation Rates

Applicants propose that transportation rates become effective January 1, 2020. Transportation rates are the end result of how the costs, post allocation, are translated to rates for which customers will be charged for gas services. As this decision has been issued after January 1, 2020, the transportation rates should become effective following Commission approval of a Tier 2 Advice Letter containing revised rates and charges implementing this

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[179] APP-18a at 30.

[180] Resolution E-4926 at 2.

[181] *Id*. at Ordering Paragraph No. 3.

decision. Parties also presented recommended modifications within the category of transportation rates which we discuss below.

6.3.1. Non-Contested Transportation Related Proposals

Applicants presented three recommendations: 1) a new optional core rate for small electric generation customers; 2) a submeter credit; and 3) a natural gas vehicle compression rate adder. No party opposed these recommendations. We address these individually below.

Applicants explain that currently, small electric generation customers are not paying a cost-based rate for their class. Applicants assert the new optional core rate for small electric generation customers would provide customers, who use less than 20,800 therms, with an option to take core service; this rate may entail transportation and procurement services or just transportation service. We find Applicants' proposal for the small electric generation customer core rate to be reasonable, as it provides another option for customers and no party presented any concerns. Applicants are authorized to implement this new tariff via the Tier 2 advice letter required to implement other requirements of this decision.

Applicants propose to decrease the submeter credit for both SoCalGas and SDG&E customers. Submeter credits apply to utility customers with a master meter who provide gas service to residential sub-units.[182] Applicants' proposed submeter credits, shown in Table 15 below, are based on an updated study in compliance with D.04-04-043. In D.04-04-043, the Commission adopted a settlement whereby the submeter credit represents costs avoided by the utility

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[182] APP-12 at 23.

when a master-metered mobile home park is sub-metered and include, for example, operations and maintenance expenses including, but not limited to, meter reading, billing, maintenance, and repair of the distribution system and services; administrative and general expenses; uncollectibles; unaccounted for gas losses; and capital investment costs. No party opposes the Applicants' proposal. While it is reasonable to grant the request to decrease the credit, Applicants have informed the Commissioner that the proposed credits are based on adoption of Applicants proposed $10 fixed charge. Hence, we authorize Applicants to present, in the required Tier 2 Advice Letter, updated submeter credits consistent with the residential minimum bill adopted in this decision.

Table 15
Submeter Credits[183]

	SoCalGas Rate (per meter/per day)		SDG&E Rate (per meter/per day)	
	Current	Proposed	Current	Proposed
Submeter credit	$0.27386	$0.13742		
Submeter credit (multi-family			$0.38268	$0.26499
Submeter credit (mobile home)			$0.40932	$0.28570

Applicants propose a natural gas vehicle compression rate adder to reflect the capital and operational costs of providing compressed natural gas to motor vehicles fueling at public access refueling stations owned and operated by Applicants. Explaining that there is one compression adder across both SoCalGas and SDG&E, Applicants note that the small difference between the adders for the two utilities is due to taxes varying by location.[184] Applicants

[183] *Ibid.*

[184] APP-12 at 24.

request approval of a compression adder of $1.04238 per therm for SoCalGas customers and $1.04809 per therm for SDG&E customers, which is derived by dividing the combined SoCalGas and SDG&E compression cost revenue requirements by the combined demand forecast for the compressed NGV volumes.[185] No party opposes the proposed adders. Accordingly, we grant the request to adopt these proposed adders.

6.3.2. Contested Transportation Related Proposals

Applicants propose to maintain the existing tariff for its core commercial and industrial customers, including Schedule G-10 for SoCalGas and Schedule GN-3 for SDG&E. Applicants describe the current G-10 rate as a $15 customer charge and three tiers of declining block volumetric rates and the current G-3 rate as a $10 customer charge and the three tiers of declining block volumetric rates.[186]

SBUA contends Applicants' proposal reduces conservation incentives, encourages increased gas use, results in lower gas prices during the winter months, and dramatically increases the transportation rates for the first tier for small businesses.[187] SBUA requests the Commission to modify the method so that the increase for the first tier is reasonable. Specifically, SBUA recommends reducing the share of costs recovered from the first tier by increasing the third tier's per therm price at the proposed increases for the first tier.[188]

[185] *Ibid*.

[186] *Ibid*.

[187] SBUA Opening Briefs at 3-4.

[188] *Id*. at 4.

Applicants explain that all customers pay the first tier rates. Because some customers may not reach up to the third tier because of their usage, all first tier customers must pay for all customer-related fixed costs over and above the customer charge. Applicants further explain that first tier rates include all functional and customer-related costs, which are fixed costs; since all customers must pass through the first tier, all fixed costs are recovered through the first tier. Hence, Applicants assert, the first tier rate needs to be higher than the third tier rate so that all customer-related costs are recoverable from all customers.[189]

The purpose of a fixed charge is to recover fixed costs from all customers. We find Applicants method reasonable because fixed costs should be recoverable from all customers. Given that all customers are charged first tier rates, all customers are therefore accountable for fixed costs. Accordingly, we deny the request of SBUA to revise Applicants' tiered rate tariff for core commercial and industrial customers.

Indicated Shippers recommend the Commission direct Applicants to provide a credit to firm Backbone Transmission Service charges during periods when a customer's Backbone Transmission Service nominations are cut as a result of pipeline or storage outages. Indicated Shippers explain that despite paying a reservation fee to secure Backbone Transmission Service rights, these rights are restricted because of operational constraints from the Aliso incident and pipeline reductions and outages.[190] Indicated Shippers, supported by TURN,[191] maintain that customers should not pay for services they are not

[189] Applicants Opening Brief at 110.

[190] Indicated Shippers Opening Brief at 44-46.

[191] TURN Opening Brief at 105 and TURN Reply Brief at 44.

receiving because of system inadequacies caused by SoCalGas' actions or inactions and should be able to recover the reservation fee. Hence, Indicated Shippers recommend the Commission direct Applicants to develop a credit mechanism to compensate customers for the limitation of services.[192]

Applicants contend that Indicated Shippers provide insufficient information to evaluate the workability or merits of their proposal. In addition, Applicants assert that Backbone Transmission Service customers have the option to nominate their capacity on an alternate firm basis when their primary capacity rights are not available.[193]

While we agree that the proposal put forth by Indicated Shippers is not complete, we find that such a credit mechanism should be developed. Accordingly, we direct Applicants to work with Backbone Transmission Service customers, including Indicated Shippers, to finalize the specifics of the proposed credit mechanism using the Indicated Shippers' proposal as a starting point. Applicants shall submit a Tier 3 Advice Letter no later than 180 days from the issuance of this decision, proposing a credit mechanism that compensates Backbone Transmission Service customers for services they pay for, but do not receive, for reasons to be determined in the Advice Letter submission.

We turn to SCE's request that the Commission initiate a rulemaking to implement an optional full requirement, cost-based gas tariff for electric generation customers. SCE contends this tariff would ensure that gas supplies for power generation are available on a cost-of-service basis. SCE provides a proposal regarding the terms and conditions of the recommended tariff. We

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[192] *Id*. at 48.

[193] Applicants Reply Brief at 24.

acknowledge the effects of Citygate market power on gas prices. However, we agree with Applicants that this proceeding in not the appropriate regulatory venue. The Commission recently issued an Order Instituting Rulemaking which, among many other natural gas-related issues, identifies the concern about the effects of Citygate market power on gas prices. Accordingly, we find SCE's request no longer necessary to address in this proceeding.

6.4. Applicants' Customer Fixed Charges, As Proposed, Are Not Reasonable and Should Not Be Adopted

Applicants' proposal for higher fixed monthly charges would result in a significant increase for customers. The Commission recognizes thatgas utilities are faced with an ever-decreasing gas throughput in California combined with an increasing pipeline replacement charges. At this time, the Commission has not determined whether a monthly fixed charge is a balanced approach to providing safe and reliable gas service to customers in an affordable manner. In a recent Order Instituting Rulemaking 20-01-007, the Commission proposed to review gas rate design and cost allocation methods, whether those rate design changes raise affordability and other economic concerns, especially for disadvantaged residential customers, and the criteria the Commission should apply when considering this issue. Accordingly, we retain the current $5/month fixed charge for SoCalGas customers and increase the current $3/month minimum charge for SDG&E customers to a $4/month minimum charge for non-California Alternate Rates for Energy (CARE) customers and $3.20/month fixed charge for CARE customers. As discussed separately below, we find these monthly fixed charges and minimum charges are consistent with current Commission rate policies and result in an appropriate balance of affordability, safety, and reliability.

Applicants propose to increase the SoCalGas residential customer charge from $5 to $10 per customer per month and the SDG&E residential customer charge from a $3 minimum charge to a $10 fixed charge per customer per month and establish a monthly charge of $8 to CARE customers of both utilities.[194] Applicants explain that customer charges are recouped costs associated with the gas infrastructure that serves all customers regardless of the amount of gas a given customer may use in a billing cycle.[195] Highlighting that the costs associated with a monthly fixed charges would otherwise be recouped in future periods through volumetric rates, Applicants imply the volumetric rates approach leads to greater bill instability. Applicants contend that ascribing a fixed customer charge would result in more stable and expected bill amounts, *i.e.* more in line with actual fixed costs.[196]

Applicants provide two charts indicating the expected impact of a $10 fixed rate on four groups of customers: 1) low usage; 2) average usage; 3) median usage; and 4) high usage. See Figure 1 below showing the impact for SoCalGas customers and Figure 2 showing the impact for SDG&E customers.

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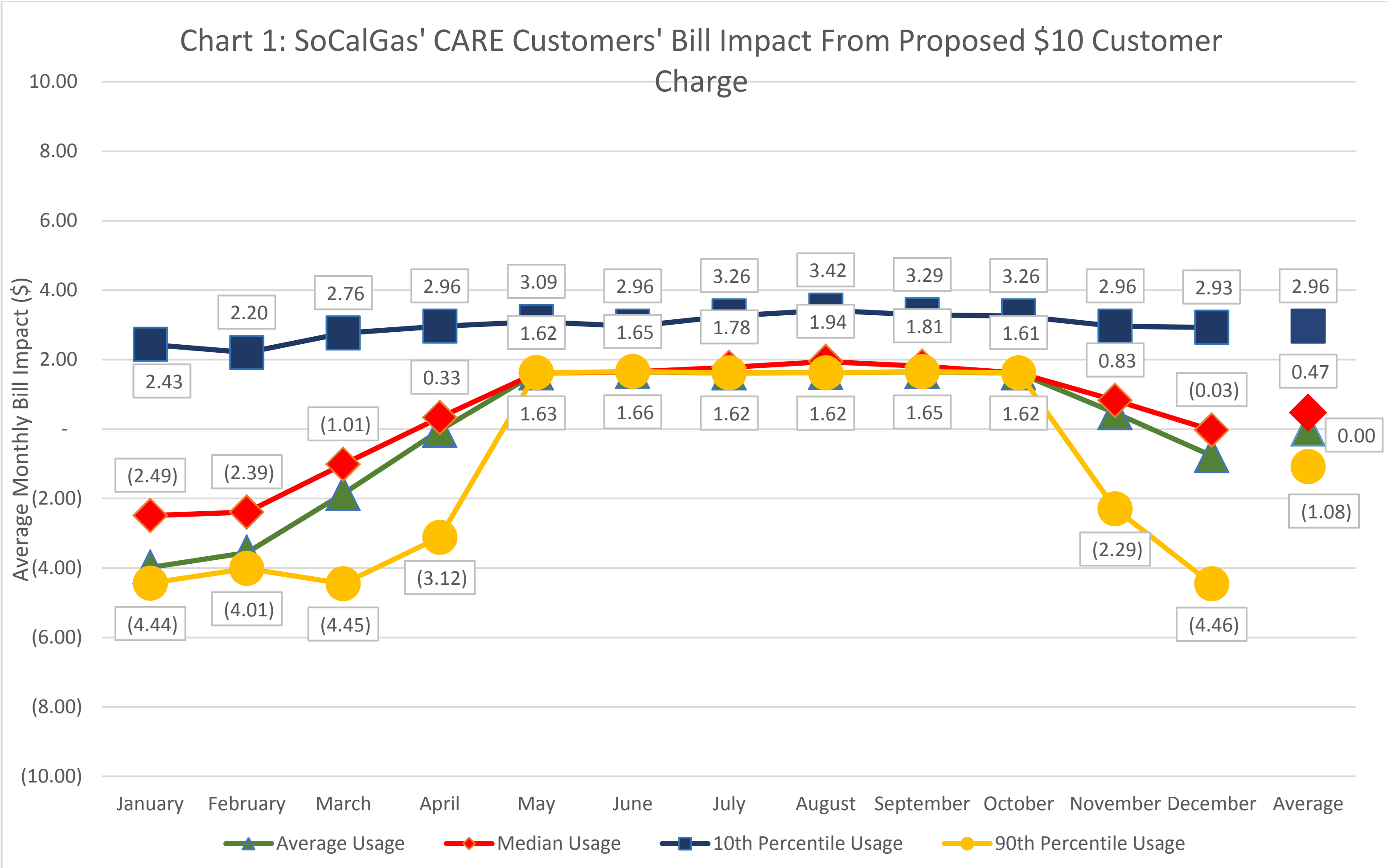
[194] Currently, SoCalGas' customer/fixed charge for non-CARE is $0.16438 per day times the number of days in the billing cycle (approximately $5 per month) with a 20 percent discount applied for CARE customers, which results in a customer charge of $0.131504 per day (approximately $4 per month). SDG&E's current minimum charge for CARE customers is 20 percent of the nonCARE minimum bill or $2.40. *See* APP-12 at 5-7.

[195] Applicants Opening Brief at 113.

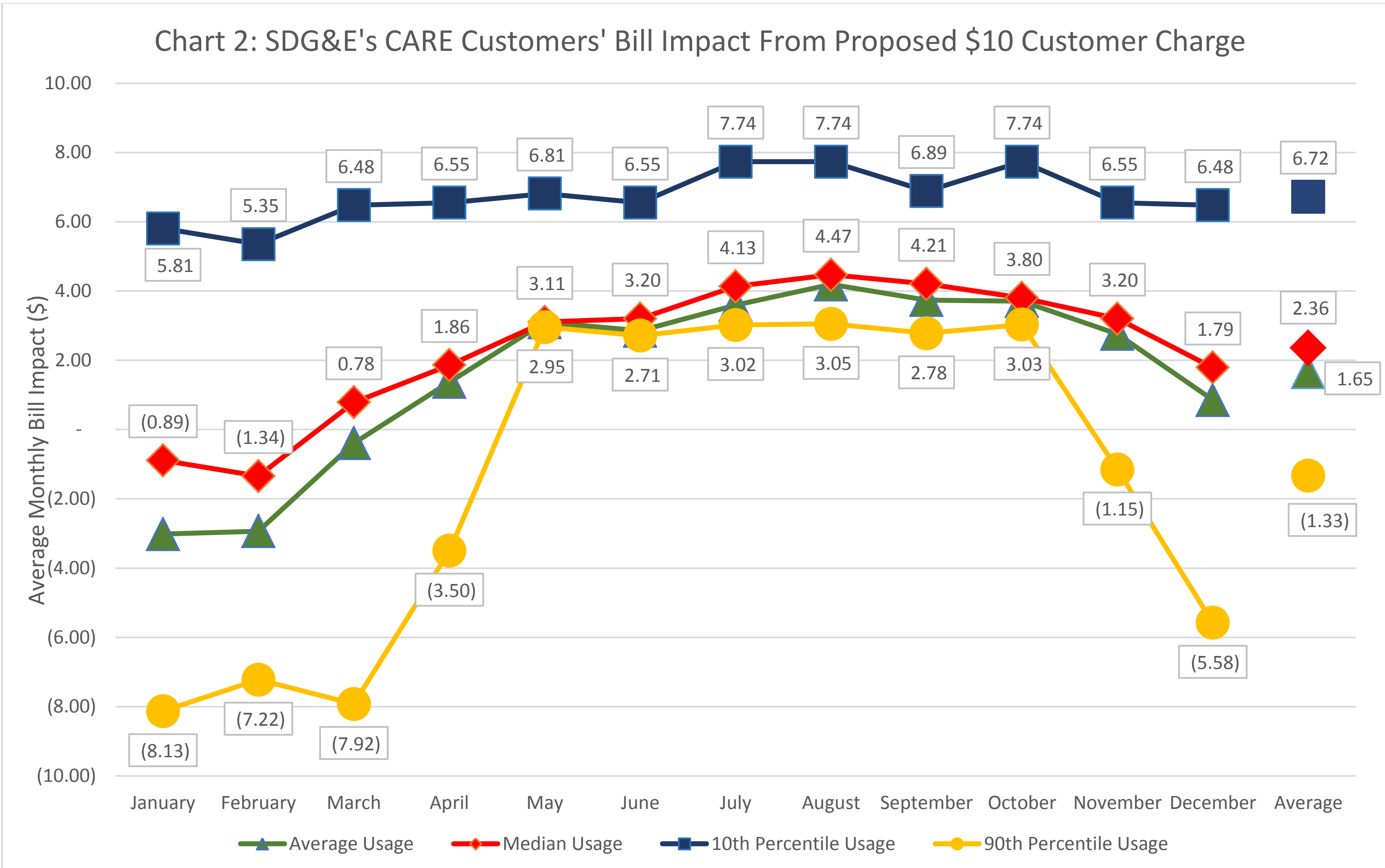
[196] *Id*. at 113-114.

Figure 1[197]



197 APP -12 at 19.

Figure 2[198]



[198] *Id*. at 21.

Both TURN and the Public Advocates Office oppose the increase in the monthly fixed charge. TURN maintains that the presence of fixed costs should not warrant adoption of a fixed charge and contends that Applicants have not adequately supported the increase request.[199] Agreeing that Applicants have not met their burden of proof, Public Advocates Office also contend Applicants are not in compliance with the Revenue Cycle Services Costs guidelines adopted in D.17-09-035.[200] Public Advocates Office allege Applicants did not present "the full range of calculations for the Residential minimum connection cost" nor did "Applicants make use of the respective cost distribution."[201]

We find Applicants' showing complies with the guidelines adopted in D.17-09-035. D.17-09-035 requires that …"SDG&E must show in their 2018 Rate Design Window proceedings their range of results applying the rental method, the new customer only method, the adjusted rental methods, and other alternatives that may be developed, bill impact analyses for each method…; and present their minimum observed cost proposals…" Public Advocates Office's allegation of more specific requirements is not found in the D.17-09-035 guidelines adopted by the Commission.

Despite our finding of compliance with D.17-09-035 we find that Applicants' request for a $10 fixed monthly residential customer charge for SDG&E and SoCalGas customers does not meet the objectives of affordability and hence, does not demonstrate that the rate increases are reasonable. We are

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[199] TURN Opening Brief at 106-107.

[200] Public Advocates Office Opening Brief at 19-20.

[201] *Ibid*.

concerned about the increased bills customers would experience as indicated by Figures 1 and 2 above.

We acknowledge the opposing objectives we face with respect to the adoption of fixed monthly residential customer charges: ensuring customer affordability and providing a safe and reliable gas system with increasing costs. We are also cognizant of the current fact that gas throughput is decreasing due to California's environmental objective of decreasing carbon reliance. We balance these circumstances by retaining the current fixed monthly residential charge of $5 for SoCalGas and increasing the current $3/month minimum charge for SDG&E customers to $4/month per customer. We recognize this minimum charge results in a less than anticipated revenue for SDG&E. However, we must balance the effect of this undercollection with the effect of the increase in bills on customers. These monthly fixed charges and minimum charges are consistent with current Commission rate policies[202] and result in an appropriate balance of affordability, safety, and reliability.

We look at our more vulnerable customer population, those SDG&E customers on CARE rates who are currently charged approximately a $2.40 minimum charge (a 20 percent discount applied to the $3 minimum charge of non-CARE rates.) An increase to $8 per customer per month fixed cost is a significant increase from the current $2.40 monthly minimum charge. However, we find it reasonable to increase the CARE rate from a $2.40 minimum charge to a $3.20 minimum charge per month ($4.00 minus 20 percent). Because we have denied the increase for nonCARE SoCalGas customers, we maintain the current

[202] D.19-10-036 at 44. *See* also D.19-10-036 at 33 and 48.

fixed charge of approximately $4 per customer per month for SoCalGas CARE customers.

Table 16 Monthly Customer Charges			
	Current	Proposed	Adopted
SDG&E			
non CARE	$3 minimum	$10 fixed	$4 minimum
CARE	$2.40	$8 fixed	$3.20 minimum
SoCalGas			
non CARE	$5 fixed	$10 fixed	$5 fixed
CARE	$4 fixed	$8 fixed	$4 fixed

The Commission recently initiated R.20-01-007, the long term gas reliability rulemaking. In the initiating order, the Commission underscores the need to implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies to meet California's decarbonization goals. Further, the Commission states that "planning for the impending demand reduction must be balanced with the need to ensure that existing transmission of gas is delivered in a safe and reliable manner, long-term statewide electricity procurement requirements are met, and rates are just and reasonable." The long-term gas reliability rulemaking, as opposed to this TCAP application, is the appropriate venue to determine overall policies regarding rate design for recovering gas infrastructure costs, including whether to adopt fixed monthly charges.

6.5. Modifications to Existing Regulatory Accounts

We address four requested modifications to existing regulatory accounts in this section. First, as we have maintained the operation of the Unbundled

Storage Program, we decline to modify the current Noncore Storage Balancing Account (NSBA) to eliminate the Unbundled Storage Program and sharing mechanism provisions. Second, we modify the Core Fixed Cost Account (CFCA) so that Southwest Gas and the City can recover their respective allocation of authorized core storage assets. Third, we eliminate the Liquified Natural Gas Service Tracking Account (LNGSTA) related to the Roadrunner mobile home park community in San Diego, CA; we agree with Applicants that no change to the rate structure would allow recovery of the balance due from Roadrunner. Fourth, we authorize the continued 100 percent balancing account treatment for the Applicants' noncore transportation revenue requirement contained in the Noncore Fixed Cost Account. We discuss each of these requested modifications and our determinations separately below.

SoCalGas' NSBA balances authorized costs for unbundled storage service with revenues collected from the Unbundled Storage Program customers. Because Applicants proposed to eliminate the Unbundled Storage Program, Applicants propose to modify SoCalGas' NSBA to eliminate provisions related to the Unbundled Storage Program and the associated sharing mechanism.[203] We previously denied the request of Applicants to eliminate the Unbundled Storage Program or the related sharing mechanism; accordingly, there is no reason to adopt the requested changes to SoCalGas' NSBA.

Relatedly, Applicants propose changes to SoCalGas' CFCA due to the proposed elimination of the Unbundled Storage Program. Applicants contend that with the elimination of the Unbundled Storage Program, storage capacities allocated to wholesale core customers (Southwest Gas and the City) should be

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[203] APP-06 at 3.

allocated from the core storage assets instead of the Unbundled Storage Program.[204] Applicants explain that because the CFCA balances revenues from core customers to recover the related authorized core storage costs, the revenues from the wholesale core customers should be balanced in the CFCA.[205] TURN and SCGC concede this modification should be made whether the Commission eliminates or maintains the Unbundled Storage Program, and maintain this would result in consistent treatment of all core storage-related revenues.[206] We find it prudent to align the treatment of all core storage-related revenues in a consistent manner. Hence, although we maintain the Unbundled Storage Program, we should grant Applicants' request to allocate wholesale core customers storage capacities from the core storage assets and balance the revenues in SoCalGas' CFCA.

Applicants request to eliminate SDG&E's LNGSTA. The Commission ordered SDG&E to establish the LNGSTA "to track the difference between the actual costs of providing liquefied natural gas services and the revenues collected from customers for such services."[207] Complying with this directive, SDG&E recorded the difference between the expenses and revenues related to the purchase and sale of liquified natural gas to the Roadrunner Mobile Home Park.[208] Applicants explain that the 2018 LNGSTA forecasted year-end balance results in an undercollection of approximately $1.1 million, which has been created by a rate structure for Roadrunner's customers that cannot exceed the

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[204] *Id*. at 5.

[205] *Ibid*.

[206] TURN Opening Brief at 123 and SCGC Opening Brief at 66-67.

[207] APP-07 at 2 citing D.94-12-052 at 97.

[208] *Id*. at 2.

average Borrego Springs all-electric user's bill.[209] Acknowledging that it does not see any change to this rate structure that would allow recovery of the balance from the Roadrunner customers, Applicants request the elimination of the LNGSTA. No party opposed the elimination of the account. We agree that the current rate structure and Commission policy does not allow for the recovery of the $1.1 million. We grant the request to eliminate SDG&E's LNGSTA and acknowledge that SDG&E will forego recovery of the $1.1 million related to the purchase and sale of liquified natural gas to the Roadrunner Mobile Home Park.

Last, Applicants request the Commission authorize the continuation of 100 percent balancing account treatment for noncore throughput/ noncore transportation revenues.[210] Applicants explain that past cost allocations have resulted in settlements, necessitating clarification from the Commission regarding whether this balancing account treatment remains effective in the Noncore Fixed Cost Account.[211] Hence, Applicants request the Commission to make this provision effective unless and until modified in a future account.[212] While not objecting to the decoupling of the Applicants' recovery of its noncore revenue requirement without throughput risk, SCGC argues this is not the time to predudge whether or not decoupling should be made permanent.[213] Agreeing with SCGC, TURN contends this is an inappropriate time to permanently insulate the Applicants' shareholders from all types of throughput risk.[214]

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[209] *Id*. at 3. *See* also D.90-11-023 at 63, D.91-12-075 at 85, D.97-04-082 at 166 and D.09-11-006 at 36.

[210] Applicants Opening Brief at 125.

[211] APP-1 at 15.

[212] Applicants Opening Brief at 125.

[213] SCGC Opening Brief at 72.

[214] TURN Reply Brief at 52.

According to the record of this proceeding, the 100 percent balancing account treatment for noncore throughput/noncore transportation revenues in the Noncore Fixed Cost Account has been in effect for several cost allocation cycles, and was uncontested in the previous cost allocation proceeding.[215] As highlighted by the Applicants, if noncore throughput is lower than forecasted, Applicants are not at financial risk and, if noncore throughput is higher than forecasted, Applicants are not in a position of financial gain.[216] Hence, Applicants and ratepayers are made whole through annual adjustments to the balancing accounts. We find it reasonable to authorize the continuation of this approach through the 2020-2022 TCAP period.

6.6. Creation of Two New Regulatory Accounts

Applicants request to establish two new regulatory accounts: Storage Inventory for SIBFMA and RFCMA. Previously we denied Applicants' proposal to procure an additional 8 Bcf for the load balancing function by adopting the modified Staff Proposal. Thus, the SIBFMA is not necessary. We also denied Applicants' request to procure 21 Bcf for a new reliability function, making the need for the RFCMA unnecessary. We discuss these requests and denials separately below.

Earlier in this decision, we discussed the Applicants' proposal to increase the allocation of storage inventory to 16 Bcf for the balancing function, which includes a load inventory allocation of 8 Bcf to accommodate for 8 percent monthly balancing.[217] Applicants explain that balancing is needed to address

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[215] APP-01 at 15.

[216] *Ibid*.

[217] APP-06 at 3.

when customers create negative imbalances by delivering less gas into the system than they use.[218] Applicants request approval for SoCalGas to procure 8 Bcf for this balancing function and establish the SIBFMA.[219] The SIBFMA will record the cost of gas used by customers creating negative cumulative imbalances up to the 8 percent monthly imbalance position by recording: a) a credit for the cost of gas associated with the reduction in the negative cumulative imbalance position and b) the carrying cost of average monthly inventory balance of the gas purchase for the balancing function.[220] As we have previously denied the request by Applicants to procure an additional 8 Bcf for the load balancing function by adopting the modified Staff Proposal, the establishment of the SIBFMA is not necessary.

As previously discussed, Applicants propose a new reliability function consisting of 21 Bcf of gas and inventory space. Relatedly, Applicants propose that SoCalGas establish the RFCMA to record the revenue requirement on the gas purchase and related costs for procuring the 21 Bcf of gas for the reliability function.[221] The RFCMA would be an interest-bearing memorandum account recorded on SoCalGas' financial statements. Here again, because we have denied the request to procure the 21 Bcf for the new Reliability function through adoption of the modified Staff Proposal, there is no need to establish the RFCMA.

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[218] *Ibid*.

[219] *Ibid*.

[220] *Id*. at 3-4.

[221] *Id*. at 4.

6.7. Existing Preliminary Statement Tariff Provisions Should Remain in Effect

As described below, we grant Applicants' request to permit the existing Preliminary Statement provisions for SoCalGas and SDG&E regulatory accounts to remain in effect, unless and until such time modifications are proposed and adopted by the Commission.

Applicants request that the Commission provide clarity as to the ongoing applicability of various tariff provisions adopted as part of prior cost allocation proceeding settlements, but which do not contain a specific expiration or termination date.[222] Applicants do not request changes to the provisions, only to make permanent the existing Preliminary Statement Tariff provisions for Applicants' regulatory accounts.[223]

SCGC opposes the request, expressing concern about the lack of specificity from Applicants. SCGC cautions that a "blanket" direction may have unintended and undesirable consequences.[224] However, we find Applicants' request for clarification to be purely administrative, as they request clarity "as to the ongoing applicability of various tariff provisions…which do not contain a specific expiration or termination date.[225] Applicants note that "including language…that makes clear that tariff provisions that were adopted as part of a cost allocation proceeding settlement (and that have no stated sunset date) continue to be effective unless and until the commission adopts modifications,

[222] Application at 10.

[223] Applicants Opening Brief at 126.

[224] SCGC Opening Brief at 35.

[225] Application at 10.

does not seem to be a controversial request."[226] We agree. Accordingly, the request to permit the existing Preliminary Statement provisions for SoCalGas and SDG&E regulatory accounts to remain in effect, unless and until such time modifications are proposed and adopted by the Commission should be granted.

6.8. Annual October Filing Should Be Formally Authorized

We grant Applicants' request to formally authorize the Applicant to submit an annual Advice Letter on October 15 to update each of the utility's regulatory account balances. No party opposes this request. As SCGC notes, the October 15 filings are established practice for which there is no specific provision in Applicants' preliminary statement.[227] Within 60 days of the issuance of this decision, SoCalGas and SDG&E shall submit a Tier 1 Advice Letter revising the tariff to include the requested authorization.

6.9. Second Daily Balancing Settlement Should Be Retained

The Commission authorizes a limited extension of the Second Settlement for this TCAP period (2020-2022). As further explained below, given the current constraints on the system, we find this a prudent outcome to address the ongoing reliability issues.

In light of the limited availability of Aliso, the Commission adopted the First Daily Balancing Settlement Agreement (First Settlement) on June 1, 2016, establishing the use of OFO tariff procedures rather than daily balancing procedures to deal with supply shortages and surpluses.[228] The initial agreement addressed summer reliability and modified OFO procedures to require end-use customers to temporarily balance their daily supply and demand within a

[226] Applicants Reply Brief at 33

[227] SCGC Opening Brief at 74.

[228] D.16-06-021 at 6.

narrow tolerance on OFO days to avert gas curtailment and potential electric grid outages pending the return of Aliso to full operation. In D.16-12-015, the Commission approved the Second Settlement, which continued the balancing process adopted in the First Settlement.[229] The terms of the Second Settlement were extended to November 30, 2018 by D.17-11-021 and subsequently extended to the implementation date of a final Commission decision in A.18-07-024 by D.18-11-009.[230]

In this proceeding, the Scoping Memo established that the Commission would determine whether to extend, make permanent, revise, or terminate the provisions of the Second Settlement. Applicants support a limited extension of the Second Settlement, in its entirety to 2022.[231] Indicated Shippers request the Commission make permanent Sections 9 and 10 of the Second Settlement, without need for future extension.[232] Similarly, SCGC, supported by TURN, request the Commission to make permanent the current language in Rule 30 that allows for the trading of scheduled quantities on OFO days and allows SoCalGas to waive OFO noncompliance charges.[233] TURN contends there has been no viable alternative to the continuation of the Second Settlement and supports its indefinite continuation until the constraints on the use of Aliso have been lifted.[234] Applicants argue that no party presented an actual case in testimony for continuing the Second Settlement, but support its continuation through the end

[229] D.16-12-015 at 3.

[230] ISH-04 at 16-17,

[231] Applicants Opening Brief at 128.

[232] ISH-04 at 17.

[233] SCGC Opening Brief at 75. *See* also TURN Opening Brief at 126.

[234] TURN Opening Brief at 125-126.

of the 2020-2022 TCAP.[235] Also supporting continuation through 2022, Shell asserts the procedures in the Second Settlement "have maintained system reliability and operational stability through a difficult period, and have minimized costs to customers."[236]

No party opposes the continuation of the Second Settlement, as previously adopted, although SCGC argues that its only necessary to adopt Rule 30 on a permanent basis.[237] We find it reasonable to extend the provisions of the Second Settlement through the end of this TCAP cycle. This is not the proceeding to address permanent solutions or plans to address ongoing reliability issues, hence, we should not extend the provisions of the Second Settlement past the life of the instant TCAP.

6.10. Applicants' Proposal to Implement SB 711 Is Reasonable

We adopt Applicants' proposal to update the baseline allowance under the current baseline structure so that it is compliant with Public Utilities Code Section 739 and SB 711. In addition, we adopt a modified baseline season such that the winter season is divided into an on-peak and off-peak season, as described below. The baseline quantity and baseline seasons shall be implemented concurrently, with SDG&E's implementation to be effective upon the approval of a Tier 2 Advice Letter submitted 30 days following the "go live" date of its Customer Information System and SoCalGas' implementation no later than 18 months from the issuance of this decision. We discuss the specifics of our determination below.

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[235] Applicants Opening Brief at 128

[236] Shell Reply Brief at 3.

[237] SCGC Reply Brief at 67.

To implement SB 711, Applicants propose a two-part process implemented simultaneously whereby they: 1) update the baseline allowances to comply with Public Utilities Code Section 739, which means reducing the residential baseline quantities to comply with the legal maximums (70 percent winter and 60 percent summer) and 2) modify the baseline seasons to divide the winter season into on peak (December, January, and February) and off-peak (November, March and April), and retain the summer season as May through October.[238] Applicants state that the baseline allowances are calculated based on 2013-2017 historical data on average consumption for each baseline season and for each SoCalGas climate zone and SDG&E.[239]

Applicants assert that modifying the baseline seasons will require both SDG&E and SoCalGas to modify their billing systems. Applicants state that SoCalGas can modify its bills to include the updated baseline seasons within 18 months from a final decision but it is not possible for SDG&E to specify at this time how long it will take to implement the required billing modifications.[240] Noting that SDG&E is currently implementing a Customer Information System replacement program, Applicants explain that a current freeze period "requires that any new structural rate changes…be deferred for one year to permit transition from the legacy [Customer Information System] to the new system."[241]

Applicants add that SB 711 also requires the Commission to direct gas corporations, for which a portion of their residential customers employ every-other-month meter reading and estimate bills for months when the customer's

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[238] Applicants Opening Brief at 131-135.

[239] *Id*. at 133 citing APP-13 at 14.

[240] APP-13 at 22-23.

[241] *Id*. at 22.

meter is not read, to include in its tariff the method it uses to estimate bills for those months during which the meter is not read. Applicants states that their existing tariffs support this requirement because the customer opting out of the Advance Meter program constitutes being beyond the Utility's control for which these rule sections apply.[242] No party opposed this proposal.

We adopt Applicants' proposed two-part process for implementing SB 711, with both parts implemented concurrently. Both Public Advocates Office and TURN support the adoption of Applicants' proposal to implement SB 711.[243] While we recognize TURN's concern over significant residential customer bill volatility, especially for SDG&E customers, TURN simultaneously recognizes the required compliance with SB 711.[244] To stave off this volatility, TURN recommends implementing the two parts of the process at different times with the first part implementing half of the baseline change the first time the season changes from winter to summer after the TCAP decision issues and the second part occurring after the new split winter season has been implemented.[245] However, as underscored by Applicants in their proposal, the updated baseline allowances would be implemented concurrently with the proposed changes to the baseline seasons, which should reduce the bill volatility more effectively than the TURN two-step approach.[246] We agree with Applicants that concurrent implementation would reduce the bill volatility more effectively.

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[242] Applicants Opening Brief at 135.

[243] Public Advocates Office Opening Brief at 23-24 and TURN Opening Brief at 128-129

[244] TURN Opening Brief at 127-128.

[245] *Id*. at 128-129.

[246] Applicants Reply Brief at 36.

We recognize the lengthy implementation period for SoCalGas, 18 months from a final decision, and the delayed implementation period for SDG&E, an unknown time period after completion of the new Customer Information System. Hence, we should monitor to limit additional delays. Accordingly, no later than 18 months from the issuance of this decision, SoCalGas shall implement the two-part process for SB 711 compliance. SoCalGas shall provide an update on its progress to the Commission's Energy Division and the service list of this proceeding 12 months and 15 months from the issuance of this decision. Given the anticipated "go live" date of January 2021 for the new Customer Information System, no later than December 31, 2020, SDG&E shall provide a letter to the Commission's Energy Division and the service list of this proceeding, presenting an update on the anticipated implementation of the Customer Information System. No later than 30 days after the actual "go live" date or 18 months from the issuance of this decision, whichever is earlier, SDG&E shall submit a Tier 2 Advice Letter notifying the Commission of the timeline for implementing the changes to the residential baseline and seasons.

7. Procedural Matters

This decision affirms all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding. All motions not ruled on are deemed denied.

8. Comments on Proposed Decision

The proposed decision of Administrative Law Judge Hymes in this matter was mailed to parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by the Applicants, California State University, Indicated Shippers, Small Business Utility Advocates, SCGC, and

TURN on February 6, 2020, and reply comments were filed on February 11, 2020 by Applicants, Indicated Shippers, California State University, Small Business Utility Advocates, and SCGC.

Clarifications and corrections have been made throughout this decision in response to the comments. We address certain comments here.

Applicants inform the Commission that three uncontested issues discussed on the record were not addressed in the proposed decision.[247] These three issues were inadvertently omitted from the proposed decision. Because the three issues were uncontested, we address them in the final decision.

In comments to the proposed decision, TURN argues that in the discussion on embedded costs for transmission storage, general and common plant costs, and miscellaneous revenues should be treated the same as A&G expenses because Applicants used the same arbitrary two-step process.[248] Applicants did not oppose this argument, stating they presumed the proposed decision implied the same treatment.[249] We agree that the costs should be treated equally and have made revisions to this decision to indicate the equal treatment.

Applicants request the Commission revise the advice letter required to implement the new option core rate for small electric generation customers from a separate Tier 3 Advice Letter to the already required Tier 2 Advice Letter, contending the Tier 3 is onerous and redundant since we are approving the uncontested rate option.[250] We agree and have made the change in this decision. We also agree with Applicants that SCGC's comments contending the

[247] Applicants Opening Comments to Proposed Decision at 6-8.

[248] TURN Opening Comments to Proposed Decision at 7-8.

[249] Applicants Reply Comments to Proposed Decision at 2, Footnote 10.

[250] Applicants Opening Comments to Proposed Decision at 10.

Commission should only approve the new optional core rate for small electric generation customers if the rate is calculated to include recovery of core fixed cost account balances are unsupported.[251]

Last, TURN contends that adoption of a $5 per month fixed customer charge conflicts with D.19-10-036, where the Commission declined to adopt an increase in Pacific Gas & Electric Company's residential minimum bill. Upon further reflection, we find this TCAP application is not the appropriate regulatory venue to determine overall policies regarding rate design for recovering gas infrastructure, including whether to adopt new fixed monthly charges. As discussed in Section 6.4 above, R.20-01-007 is the more appropriate venue to consider these changes across all related utilities.

9. Assignment of Proceeding

Martha Guzman Aceves is the assigned Commissioner and Kelly A. Hymes is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. There is insufficient basis for adopting the SCGC proposal to adjust the Electric Generation demand forecast.

2. The significant reductions proposed by SCGC in its demand forecast proposal are not warranted as the curtailments did not occur until after the pipeline outages.

3. Line 235-2 returned to service on October 14, 2019 and Line 4000 returned to service at reduced pressure on October 24, 2019.

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[251] Applicants' Reply Comments to Proposed Decision at 4 citing SCGC Opening Comments to Proposed Decision at 12. *See* also California State University Reply Comments to Proposed decision at 1-2.

4. Subsequently, Line 235-2 was taken out of service for remediation but returned again to service on February 15, 2020.

5. Applicants' demand forecast for core and noncore customers represents reasonable weather design and temperature design value.

6. TURN's proposal to revise the peak day for the large commercial and industrial customers served under the G-30 schedule is based on data provided by SoCalGas.

7. No party opposes Applicants' request that the unaccounted-for gas percentages provided in testimony for ratemaking purposes be updated and based on the April 2015 to March 2018 three-year average of 0.926 percent for SoCalGas and 0.565 for SDG&E.

8. No party opposes Applicants' request to adopt the proposed brokerage fee of 0.207 cents per therm, which is based on an updated core brokerage fee study consistent with prior cost allocation proceedings.

9. Compressor station equipment exists on the backbone transmission system.

10. The use of compressor station equipment supports customers on local transmission systems.

11. It is reasonable to allocate compressor station operation and management expenses based on mileage to both backbone transmission and local transmission.

12. TURN's recalculated cost allocations process is inconsistent.

13. Using percentage escalation factors to escalate recorded costs could introduce errors and artificially alter the results of the embedded cost study.

14. Not all embedded costs will rise proportionally over time.

15. It is more precise for allocation purposes to use older but recorded (*i.e.*, actual) costs.

16. Using the Applicants' embedded cost study provides results that are more constant across all customer classes in comparison with the TURN proposal.

17. Applicants' step of allocating half of the A&G expenses, general and common plant costs, and miscellaneous revenues to end users is arbitrary and unreasonable.

18. Applicants provide no other logic for their two-step approach except that the approach was adopted through prior settlements, which Applicants acknowledge is not precedential.

19. The impact of the two-step process becomes clear with the inclusion of all A&G expenses.

20. Company labor is a key factor that drives A&G expenses.

21. Allocating 100 percent of the A&G expenses, general and common plant costs, and miscellaneous revenues using the key factor labor percentages is a more balanced approach in comparison to the two-step process recommended by Applicants.

22. Asset Retirement Obligations are not a product of a financial reporting requirement.

23. Asset Retirement Obligations are asset-related incremental costs.

24. Applicants offer no additional reasoning for assigning the Customer Advances for Construction amounts to both transmission and distribution except that Applicants do not believe the impact to the embedded cost study would be material.

25. No party disputes the fact that there are no Customer Advances for Construction for transmission.

26. The Staff Proposal for storage allocation best meets the needs of a fluctuating storage inventory.

27. Prorating daily available injection and withdrawal capacity support a proportionate reduction of withdrawal and injection capacity based on customer cost allocation shares.

28. The percentage allocations in the Staff Proposal better reflect the operational needs of each function.

29. As inventory in a gas storage field declines, its corresponding withdrawal capacity is reduced.

30. Injection capacity tends to decrease as storage fields become full.

31. The proposed amendments to SoCalGas Rule 30 regarding extending Intraday Cycle 4 and the deadline for imbalance trading support an improved opportunity to cure imbalances.

32. Applicants' proposal to incorporate any necessary update to transportation rates as part of an otherwise scheduled rate change is efficient.

33. Cost allocations should not change dramatically as a result of changes to transportation rates; thus minimizing any concern of incongruence between the TCAP allocations and reality.

34. Any concern of incongruence between the TCAP allocation and reality is minimal is addressed by a $5 million cost allocation threshold.

35. The Staff Proposal results in a ten percent reduction from the 83 Bcf currently allocated to bundled core customers.

36. The November 1 target of 83 Bcf for the Gas Cost Incentive Mechanism is not achievable given the core allocation of 74.6 Bcf in the Staff Proposal.

37. Changes to the Aliso Withdrawal Protocol are not in the scope of this proceeding.

38. Revising core limitations is not in the scope of this proceeding.

39. The proposed sharing mechanism is not necessary for overall system reliability purposes.

40. The proposed sharing mechanism provides a balanced and fair approach for risk and reward sharing between shareholders and ratepayers.

41. The effects of the Tax Cut and Jobs Act will be across all customers classes with no material impact of one class over the other.

42. Parties generally support the use of the LRMC method to allocate customer-related, medium-pressure, and high-pressure distribution-related costs.

43. The major contention with respect to the LRMC method is the use of the Rental Method versus the New Customer Only Method to calculate marginal customer costs.

44. Neither the Rental Method nor the New Customer Only Method are optimal approaches to determining marginal costs.

45. The results of the Rental Method provide marginal costs with less dramatic increases across all customer classes and avoid disproportionate rate impacts to customer classes with few new customers.

46. The use of the Rental Method in this proceeding will result in the most reasonable revenue allocation and near cost-based rates for SoCalGas and SDG&E customers.

47. The essential element in the selection of a reasonable cost allocation method is the establishment of relationships between customer requirements, load profiles and usage characteristics, and the cost incurred by the utility in serving those requirements.

48. In the past, the Commission has supported the Rental Method and the New Customer Only Method for varying reasons.

49. In this review of the Rental Method and the New Customer Only Method, we have been presented with as in prior proceedings.

50. Neither the supporters of the Rental Method nor the supporters of the New Customer Only Method fully validate the use of its preferred model but rather focus on invalidating the opposing model.

51. We have two imperfect models in the Rental Method and the New Customer Only Method.

52. The Rental Method results in costs that are fair across the customer classes.

53. SoCalGas' cost allocation methodology allocates large commercial and industrial and economic development program costs only to large and very large G-10 customers and the Applicants' proposal that large commercial and industrial and economic development program costs for SoCalGas be allocated to all SoCalGas Schedule G-10 customers is an oversight by Applicants.

54. The high-pressure distribution O&M cost allocation increase to ten percent for measuring and regulating stations aligns with the ten percent of SDG&E's measurement and regulating stations that are related to the interface between transmission and high pressure distribution pipelines.

55. $16.2 million is the correct value for the service line O&M cost.

56. Applicants' LRMC study includes a method for calculating cathodic protection costs that results in SDG&E allocating more cathodic protection costs for services than the total amount spent on cathodic protection.

57. No one disputes TURN's updated method of using direct cathodic protection costs and allocation based on only cathodically protected miles as opposed to all miles.

58. Applicants' SGIP cost allocation proposal places a majority of the cost responsibility on the core commercial and industrial customers for SDG&E and noncore Electric Generation customers for SoCalGas, a large portion of whom are not eligible for SGIP incentives.

59. With the SCGC proposal, 129 of the 428 customers who received SGIP incentives would not contribute in an equitable manner to the SGIP costs.

60. Neither Applicants nor SCGC's proposal for the allocation of SGIP costs result in an equitable distribution of the costs and benefits of the SGIP.

61. The hybrid approach for allocating SGIP costs is not a perfect approach.

62. The hybrid approach for allocating SGIP costs represents the most equitable distribution of the costs and benefits at this time.

63. Resolution E-4926 required SDG&E and SoCalGas to file proposal to allocate costs on the basis of the actual benefits resulting from the disbursement of program incentives over the previous three years.

64. The current method for recovery of SGIP costs employed by SoCalGas inappropriately recovers SGIP costs from wholesale customers.

65. This decision has been issued after January 1, 2020.

66. Small electric generation customers are not paying a cost-based rate for their class.

67. No party presented any concerns regarding Applicants' proposal for the small electric generation customer core rate.

68. Applicants' proposal for the small electric generation customer core rate provides another option for customers.

69. Applicants' proposed submeter credits are based on an updated study in compliance with D.04-04-043.

70. No party opposes the Applicants' proposal to decrease the submeter credit for both SoCalGas and SDG&E customers.

71. Applicants' proposal to decrease the submeter credit for both SoCalGas and SDG&E customers is based on the $10 fixed monthly charge.

72. No party opposes Applicants' proposed compression adders.

73. The purpose of a fixed charge is to recover fixed costs from all customers.

74. All customers are charged first tier rates in Applicants' G-10 tariff.

75. All customers are accountable for fixed costs in Applicants' G-10 tariff.

76. Applicants' G-10 tariff is reasonable.

77. Indicated Shippers' proposal for a backbone transmission service credit mechanism is not complete but should be developed.

78. Citygate market power affects gas prices.

79. This proceeding is not the appropriate regulatory venue to address the effect of Citygate market power on gas prices.

80. The Commission recently issued an Order Instituting Rulemaking that identifies as a scoped issue the effect of Citygate market power on gas prices.

81. D.17-09-035 requires that SDG&E show their range of results applying the Rental Method, the New Customer Only Method, the adjusted Rental Method, and other alternatives that may be developed, bill impact analyses and present their minimum observed cost proposals but does not require more specific information as alleged by Public Advocates Office.

82. The Applicants' showing for customer fixed charges complies with the guidelines adopted in D.17-09-035.

83. The Applicants' request for a $10 fixed monthly residential customer charge for SDG&E and SoCalGas customers does not meet the objective of affordability.

84. Applicants do not demonstrate that the $10 fixed monthly residential customer charge for SDG&E and SoCalGas customers is reasonable.

85. Gas throughput is decreasing due to California's environmental objective of decreasing carbon reliance.

86. The monthly fixed charge of $5 for SoCalGas customers and minimum charge of $4 per month for SDG&E customers are consistent with current Commission rate policies and result in an appropriate balance of affordability, safety, and reliability.

87. An increase from a $2.40 minimum bill to an $8 fixed charge each month for SDG&E CARE customers is a significant increase.

88. The Commission initiated the long term gas reliability rulemaking.

89. The long-term gas reliability rulemaking, as opposed to this TCAP application, is the appropriate venue to determine overall policies regarding rate design for recovering gas infrastructure costs, including whether to adopt fixed monthly charges.

90. Through the adoption of the modified Staff Proposal, we have denied the request of Applicants to eliminate the Unbundled Storage Program and the related sharing mechanism.

91. There is no reason to adopt the requested changes to SoCalGas' NSBA.

92. It is prudent to align the treatment of all core storage-related revenues in a consistent manner.

93. No party opposed the elimination of the LNGSTA.

94. The current rate structure and Commission policy do not allow for the recovery of the $1.1 million undercollection in the LNGSTA.

95. The Noncore Fixed Cost Account has been in effect for several cost allocation cycles, and was uncontested in the previous cost allocation proceeding.

96. If noncore throughput is lower than forecasted, Applicants are not at financial risk and, if noncore throughput is higher than forecasted, Applicants are not in a position of financial gain. Applicants and ratepayers are made whole through annual adjustments to the balancing accounts.

97. We have denied the request by Applicants to procure the additional 8 Bcf for the balancing function by adoption of the modified Staff Proposal.

98. If the Increased Capacity Scenario is triggered and core's allocation reaches 82.5 Bcf, the modified Staff Proposal allows Applicants to allocate additional inventory capacity to the load balancing function, up to an additional 2 Bcf, for a total of 10 Bcf.

99. The establishment of the SIBFMA is not necessary.

100. The request for clarity regarding the ongoing applicability of various tariff provisions, which do not have specific expiration or termination dates is administrative.

101. No party opposes Applicants' request for authorization to submit an annual Advice Letter on October 15 to update each of the utility's regulatory balancing accounts.

102. The October 15 filings are established practice for which there is no specific provision in Applicants' Preliminary Statement.

103. No party opposes continuation of the Second Settlement.

104. This proceeding is not the appropriate regulatory venue to address permanent solutions or plan for the constraints on Aliso.

105. The Applicants' contention that its existing tariffs currently include the method for estimating bills, as required by SB 711, is uncontested by parties.

106. Parties support adoption of Applicants' proposal to implement SB 711.

107. The concurrent implementation of updated baseline allowances and revised baseline seasons reduces bill volatility more effectively than TURN's two step approach.

108. With respect to implementing new baseline allowances and revised baseline seasons, SoCalGas's proposes a lengthy 18-month implementation period and SDG&E proposes implementation in an unknown time period following the completion of a new Customer Information System.

109. It is reasonable for the Commission to monitor the implementation of SB 711 as well as SDG&E's Customer Information System to limit additional delays.

110. All issues in the scope of this proceeding have been resolved.

Conclusions of Law

1. The Applicants' demand forecast for core and noncore customers should be adopted.

2. TURN's proposal to increase the peak day for a portion of the G-30 class should be adopted.

3. The Commission should adopt the unaccounted-for gas percentages and allocation factors for ratemaking purposes.

4. The Commission should adopt a brokerage fee for Applicants of 0.207 cents per therm.

5. The Commission should not adopt TURN's recalculated cost allocation.

6. The Commission should require the Applicants to use the most recent embedded costs from the FERC Form and allocate compressor station operation

and management expenses based on mileage to both backbone transmission and local transmission.

7. The Commission should allocate 100 percent of the A&G expenses, costs of general and common plant, and miscellaneous revenues using the key factor labor percentages.

8. Asset Retirement Obligations should be included in the embedded cost study.

9. Customer Advances for Construction amounts should be assigned to distribution despite the change being immaterial in this proceeding.

10. The Commission should adopt the use of prorating daily available injection and withdrawal capacity based on the maximum authorized capacity.

11. The Staff Proposal for storage allocation should be adopted but modified in response to comments.

12. The two amendments to SoCalGas' rule 30 as proposed by Applicants and SCGC should provide an improved opportunity to cure imbalances.

13. The Commission should authorize Applicants to incorporate any necessary update to transportation rates that result from changes in storage capacity during this TCAP cyle as part of an otherwise scheduled rate change, subject to the threshold for submitting a separate Advice Letter as identified in this decision.

14. The Commission should adopt a $5 million threshold of a cost allocation change, which, if reached, will require the submission by Applicants of a Tier 2 Advice Letter the following month.

15. SoCalGas should be authorized to modify its storage inventory targets by submitting a Tier 2 Advice Letter.

16. Changes to the Aliso Withdrawal Protocol should not be considered in this proceeding.

17. The Commission should not consider changing the current core limitations to purchase firm pipeline receipt contracts in this proceeding.

18. The Commission should maintain the sharing mechanism with the limited Unbundled Storage Program.

19. The Commission should not require Applicants to update the LRMC study with 2018 data.

20. The Commission should adopt a revision to Schedule G-10 whereby large commercial and industrial and economic development costs are allocated only to large and very large G-10 customers.

21. The Commission should increase the high-pressure distribution O&M cost allocation for measurement and regulating stations to 10 percent.

22. The service line O&M costs should be corrected to $16.2 million.

23. The Commission should adopt the use of the TURN method to calculate cathodic protection costs, based on only cathodically protected miles versus all miles.

24. The Commission should adopt the hybrid approach to allocate the costs of the SGIP equally between the host customer class and the receiving customer class.

25. Public Utilities Code Section 379.6(a)(1), requires the Commission to ensure an equitable distribution of the costs and benefits of the SGIP.

26. SoCalGas should revise its SGIP cost allocation method such that wholesale customers are not responsible for SGIP costs.

27. Transportation rates should become effective following Commission approval of a Tier 2 Advice Letter containing revised rates and charges implementing this decision.

28. The Commission should adopt Applicants' proposal to provide small electric generation customers with an option to take core service.

29. The Commission should authorize Applicants to present updated submeter credits consistent with the fixed and minimum bill charges adopted in this decision.

30. The Commission should grant Applicants' requested natural gas vehicle compression rate adder.

31. Fixed costs should be recoverable from all customers

32. The Commission should maintain the existing rate structure for Applicants' core commercial and industrial customers.

33. Applicants should work with Backbone Transmission Service customers to finalize the specifics of the proposed credit mechanism to compensate these customers for service limitations.

34. It is not necessary to address the effects of Citygate market power on gas prices in this proceeding.

35. The Commission should balance the opposing objectives of ensuring customer affordability and providing a safe and reliable gas system with increasing costs.

36. The Commission should not adopt Applicants' proposed monthly customer charges of $10 for non-CARE customers and $8 for CARE customers.

37. The Commission should retain the current fixed monthly residential charge of $5 for SoCalGas customers.

38. The Commission should increase the monthly minimum charge to $4/month per SDG&E customer.

39. The Commission should increase the CARE rate to $3.20 minimum charge per month for SDG&E CARE customers.

40. The Commission should not authorize the elimination of the provisions of the NSBA related to the Unbundled Storage Program and the associated sharing mechanism.

41. The Commission should grant Applicants' request to allocate wholesale core customers' storage capacities from the core storage assets and balance the revenues in SoCalGas' CFCA.

42. The Commission should grant Applicants' request to eliminate SDG&E's LNGSTA.

43. The Commission should authorize the continuation of the 100 percent balancing account treatment for the Applicants' noncore transportation revenue requirement as currently contained in the Noncore Fixed Cost Account, through the 2020-2022 TCAP period.

44. The Commission should deny Applicants' request to establish the SIBFMA.

45. The Commission should deny Applicants' request to establish the RFCMA.

46. The Commission should clarify that tariff provisions adopted as part of a settlement continue to be effective unless and until the Commission adopts modifications to those provisions.

47. The Commission should authorize Applicants to submit an annual Advice Letter on October 15 to update each utility's regulatory accounts.

48. The Commission should extend the provisions of the Second Settlement through the end of this TCAP cycle.

49. The Commission should authorize Applicants to simultaneously: 1) update the baseline allowance to comply with Public Utilities Code Section 739 and 2) modify the baseline seasons to divide the winder into on peak and off peak.

50. The Commission should monitor the implementation of the baseline allowance and baseline season to limit additional delays.

51. The Commission should close A.18-07-024.

O R D E R

IT IS ORDERED that:

1. The demand forecast for core and non-core customers, as provided by San Diego Gas & Electric Company and Southern California Gas Company, is adopted with one change: the portion of the G-30 class served at medium-pressure distribution levels shall have a peak day that is a weekday with 23 heating degree days, which results in a peak day load of 1,152,900 therms. The effective date for the demand forecast is 30 days from the issuance of this decision.

2. The unaccounted-for gas percentages and allocation factors proposed by San Diego Gas & Electric Company and Southern California Gas Company are adopted and shall be used for ratemaking purposes.

3. The brokerage fee proposed by San Diego Gas & Electric Company and Southern California Gas Company is adopted.

4. San Diego Gas & Electric Company (SDG&E)and Southern California Gas Company (SoCalGas) are authorized to allocate transmission and storage costs in the following manner: a) use the most recent embedded costs from the Federal Energy Regulatory Commission 2 form; b) with respect to backbone transmission costs, SDG&E and SoCalGas shall allocate compressor station operation and

management expenses based on mileage to both backbone transmission and local transmission; c) allocate 100 percent of the Administrative and General expenses using the key factor labor percentages; d) include asset retirement obligations in the embedded cost study; and e) assign Customer Advances for Construction amounts to distribution.

5. The Energy Division Staff Proposal on Storage Capacity Allocation is adopted with the following modifications, as indicated in Appendix A of this decision: a) San Diego Gas & Electric Company and Southern California Gas Company (SoCalGas) (Applicants) shall prorate the daily available injection and withdrawal capacity based on the maximum authorized capacity; b) the Intraday Cycle 4 (also known as the Cycle 6) deadline is extended from 9:00 p.m. on the gas day to 9:00 p.m. on the day following the gas dayand the deadline for imbalance trading is extended to 9:00 p.m. on the business day following the close of Cycle 6; c) Applicants shall file a Tier 2 Advice Letter by the first day of the following month if the maximum allowable inventory at the Aliso Canyon Storage Facility is revised from the current 34 billion cubic feet; and d) no later than August 1, 2020, SoCalGas is authorized to submit a Tier 2 Advice Letter to request modification of its storage targets.

6. Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) may incorporate any necessary update to transportation rates that result from changes in storage inventory capacity during this triennial cost allocation proceeding cycle as part of an otherwise scheduled rate change, except where cost allocation has changed by $5 million or more. If the $5 million threshold is met, SoCalGas and/or SDG&E shall submit a Tier 2 Advice Letter by the 15th day of the month following such a change. The

Advice Letter shall provide allocated costs and illustrative class-average rate changes and related work papers.

7. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) are authorized to use the Long Run Marginal Cost Method, with the Rental Method to determine cost allocation by customer classes and with the following four modifications: a) allocate SoCalGas' commercial and industrial and economic development costs only to large tariff Schedule G-10 large and very large customers; b) increase the high-pressure distribution Operation and Management costs allocation rate to ten percent for SDG&E's measurement and regulatory stations; c) correct the service line Operation and Management costs amount to $16.2 million; and d) revise the method for calculating cathodic protection costs using direct cathodic protection costs and allocation based on cathodically protected miles only.

8. San Diego Gas & Electric Company and Southern California Gas Company shall continue to provide customer cost allocation results in future Triennial Cost Allocation Proceeding applications using the Long Run Marginal Cost Method and the four approaches, as previously directed in Decision 17-09-035.

9. San Diego Gas & Electric Company and Southern California Gas Company shall modify the method by which they allocate the costs for the Self Generation Incentive Program (SGIP) by: a) dividing the SGIP costs by two and allocating half of the costs to the host customer class and half to the receiving customer class; and b) ensuring that wholesale customers are not responsible for SGIP costs.

10. Transportation rates approved in this decision shall be effective following Commission approval of the Tier 2 Advice Letter containing revised rates and

charges implementing this decision, as required by Ordering Paragraph 23 of this decision.

11. San Diego Gas & Electric Company and Southern California Gas Company are authorized to implement a new optional core rate for small electric generation customers through the Tier 2 Advice Letter implementing this decision, as required by Ordering Paragraph 23 of this decision.

12. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) shall present, in the Tier 2 Advice Letter required in Order Paragraph 23 below, updated submeter credits consistent with the residential fixed and minimum charges adopted in this decision for SDG&E and SoCalGas customers.

13. The proposal by San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) to implement a natural gas vehicle compression rate adder is adopted. SDG&E shall implement a compression rate adder of $1.04238 and SoCalGas shall implement a compression rate adder of $1.04809.

14. San Diego Gas & Electric Company and Southern California Gas Company (Applicants) shall work with the Backbone Transmission Service customers to finalize the specifics of the proposed credit mechanism. No later than 180 days from the issuance of this decision, Applicants shall submit a Tier 3 Advice Letter requesting approval for the final credit mechanism that compensates Backbone Transmission Service customers for services they pay for but do not receive, for reasons beyond the control of the customer.

15. Southern California Gas Company (SoCalGas) is directed to maintain the current $5 per month per customer fixed charge for SoCalGas customers and the

current $4 per month per customer fixed charge for SoCalGas customers of California Alternate Rates for Energy, also referred to as CARE.

16. San Diego Gas & Electric Company (SDG&E) is authorized to implement a $4 per month per customer minimum charge. SDG&E is authorized to implement a $3.20 per month per customer minimum charge for SDG&E customers of California Alternate Rates for Energy, also referred to as CARE.

17. Southern California Gas Company is authorized to allocate wholesale core customers' storage capacities from the core storage assets and balance the revenue in its Core Fixed Cost Account.

18. San Diego Gas & Electric Company is authorized to eliminate its Liquefied National Gas Service Tracking Account.

19. San Diego Gas & Electric Company and Southern California Gas Company (Applicants) are authorized to continue 100 percent balancing account treatment for Applicants' noncore transportation revenue requirement as currently contained in Applicants' Noncore Fixed Cost Accounts through this triennial cost allocation proceeding cycle.

20. San Diego Gas & Electric Company and Southern California Gas Company are authorized to submit a Tier 2 Advice Letter creating the Storage Inventory for Balancing Function Memorandum Account no later than 60 days after Aliso Canyon Storage Facility's inventory is increased above 34 billion cubic feet and the Increased Capacity Scenario is triggered. The existing Preliminary Statement provisions for San Diego Gas & Electric Company and Southern California Gas Company shall remain in effect, unless and until such time modifications are adopted by the Commission.

21. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) are authorized to each submit an annual Advice Letter on

October 31 and October 15, respectively, to update each of the utility's regulatory account balance. Within 60 days of the issuance of this decision, SDG&E and SoCalGas shall each submit a Tier 2 Advice Letter revising the tariff to include the requested authorization.

22. The terms of the Second Daily Balancing Settlement Agreement, previously adopted in Decision 16-12-015, are applicable until an adopted decision is issued in the next triennial cost allocation proceeding for San Diego Gas & Electric Company and Southern California Gas Company. .

23. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) shall each submit an Tier 2 Advice Letter no later than 30 days following the issuance of this decision that contains revised rates and charges that implement the demand forecasts, cost allocations, customer charges, and rate designs adopted by today's decision. The revised tariff sheets contained in these Advice Letters shall be effective on the first of the month following Commission approval of the Advice Letters.

24. The proposal to implement Senate Bill (SB) 711, as proposed by San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas), is adopted. No later than 18 months from the issuance of this decision, SoCalGas shall implement the two-part process for SB 711 compliance. At 12 months from the issuance of this proceeding, and again at 15 months from the issuance of this proceeding, SoCalGas shall provide an update on the progress of this implementation to the Director of the Commission's Energy Division and the service list of Application 18-07-024. No later than December 31, 2020, SDG&E shall provide a letter to the Director of the Commission's Energy Division and the service list of this proceeding, presenting an update on the anticipated implementation of the Customer Information

System. No later than 30 days after the full implementation of the Customer Information System, SDG&E shall submit a Tier 2 Advice Letter notifying the Commission of the timeline for implementing the changes to the residential baseline and seasons pursuant to SB 711.

25. All rulings made by the Administrative Law Judge and assigned Commissioner are affirmed. All motions not ruled on are hereby denied.

26. Application 18-07-024 is closed.

This order is effective today.

Dated February 27, 2020, at San Francisco, California.

MARYBEL BATJER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners